DEVELOPMENT OF DIRECTIONAL CAPABILITIES TO AN ULTRADEEP WATER DYNAMIC KILL SIMULATOR AND SIMULATION RUNS

A Thesis

by

HECTOR ULYSSES MEIER

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2005

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee, Jerome J. Schubert

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August 2005

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ABSTRACT

Development of Directional Capabilities to an Ultradeep Water Dynamic Kill Simulator and Simulation Runs.
(August 2005)
Hector Ulysses Meier, B.S., Texas A&M University
Chair of Advisory Committee: Dr. Jerome J. Schubert

The world is dependent on the production of oil and gas, and every day the demand increases. Technologies have to keep up with the demand of this resource to keep the world running. Since hydrocarbons are finite and will eventually run out, the increasing demand of oil and gas is the impetus to search for oil in more difficult and challenging areas. One challenging area is offshore in ultradeep water, with water depths greater than 5000 ft. This is the new arena for drilling technology. Unfortunately with greater challenges there are greater risks of losing control and blowing out a well. A dynamic kill simulator was developed in late 2004 to model initial conditions of a blowout in ultradeep water and to calculate the minimum kill rate required to kill a blowing well using the dynamic kill method. The simulator was simple and efficient, but had limitations; only vertical wells could be simulated. To keep up with technology, modifications were made to the simulator to model directional wells. COMASim (**C**herokee, **O**ffshore Technology Research Center, **M**inerals Management Service, Texas **A**&M **Sim**ulator) is the name of the dynamic kill simulator. The new version, COMASim1.0, has the ability to model almost any type of wellbore geometry when provided the measured and vertical depths of the well.

Eighteen models with varying wellbore geometry were simulated to examine the effects of wellbore geometry on the minimum kill rate requirement. The main observation was that lower kill rate requirement was needed in wells with larger measured depth.

COMASim 1.0 cannot determine whether the inputs provided by the user are practical; COMASim 1.0 can only determine if the inputs are incorrect, inconsistent or cannot be computed. If unreasonable drilling scenarios are input, unreasonable outputs will result. COMASim1.0 adds greater functionality to the previous version while maintaining the original framework and simplicity of calculations and usage.

DEDICATION

I dedicate this thesis to my parents and my brother. They have supported me and encouraged me to reach for the stars and follow my dreams.

ACKNOWLEDGEMENTS

I would like to first thank Dr. Jerome J. Schubert, Dr. Hans Juvkam-Wold, and Dr. Brann Johnson for helping me with this thesis and for being on my committee.

Thanks also go to Dr. Tom Blasingame for giving me a chance and convincing me to go to graduate school. I do not regret it. I am grateful to Dr. Ray T. Oskarsen for his tremendous help and insight; thank you for always having time to answer my numerous questions. I would also like to thank Eirik Grøtthiem, for being a great friend and a good office mate; and Texas A&M University and the petroleum engineering department for giving me a solid foundation and teaching me all that I needed to perform this task.

I also would like to recognize RPSEA (Research Partnership to Secure Energy for America), MMS (Minerals Management Service) and OTRC (Offshore Technology Research Center) for their contribution to this study.

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Thank you everyone!

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1. INTRODUCTION

Demand for oil and gas is constantly increasing and is showing no signs of slowing down. This trend will continue until a new economical energy source is developed or the quantity of oil and gas available starts to decrease. The strong demand for this resource can, in part, be attributed to the inescapable increase in world population. Another reason for this demand stems from the economic development of countries that previously had low energy per-capita consumption. As long as the demand for this precious commodity exists, a need for economical recovery methods will exist – no matter what type of environment. Lately much effort has been expended to find and develop reservoirs offshore in ultradeep water environments – once thought impossible to reach. On the 7th of January 2004, ChevronTexaco used the Transocean drillship, *Discoverer Deep Seas*, to set a new world's record by drilling into ultradeep waters with a depth of 10,011 feet. [1] Certainly this record will be shattered and replaced by another. This pattern will continue until the deepest water depth has been achieved or it becomes more economical to use a different fuel source.

Another feat in drilling technology is the invention of the steerable motor used for drilling wells in any given direction. Since this invention, offshore reservoirs are now commonly developed by directional drilling. Current trends in technology have not made drilling wells antiquated; as long as drilling is used to get to the reservoir blowouts will periodically occur. Blowouts occur when the entry of formation fluids into the wellbore cannot be controlled. Humans make mistakes, equipment will fail and accidents will occur, this is inevitable. Being prepared for this disastrous occasion can save time, lives and cost.

This thesis follows the style of *SPE Drilling and Completion.*

1.1 Directional Drilling and Ultradeep Water

Ultradeep waters are defined as waters deeper than 5,000 ft. Since 1 January 2000 to 24 April 2005, 30 wells have been drilled in ultradeep water in the Gulf of Mexico.[2] Directional drilling technology is common in offshore operations to reduce total drilling costs accrued while developing a reservoir. Drilling economics dictate how many ultradeep water wells are drilled per year, as drilling in deeper water becomes cheaper more wells will be drilled.

One of the first reasons to drill directionally was due to fishing an unrecoverable drill tool in the wellbore; drilling a new well would be more costly than drilling around it.[3] Today there are many other reasons to use directional drilling technology. A common application is sidetracking in order to move around a lost tool or other obstruction. Directional drilling also is used in drilling offshore salt domes. When drilling offshore, salt domes are prevalent and provide structural traps at their flanks. Another reason to drill directionally is to drilling a perfectly vertical well. This at first appears paradoxical, but in reality it is nearly impossible to drill a true vertical well. For that reason directional drilling is needed to maintain the drilling as vertical as possible. At times a reservoir can lie under natural or manmade obstructions where permission may not be granted to drill on the surface therefore directional drilling is used to drill underneath the surface to recover the hydrocarbons. Over the past 20 years the major application for direction drilling has been for the development of offshore reservoirs.[4] Developing offshore reservoirs are more economical and practical to drill from one central location than drilling numerous distributed wells. Typically deviated wells are drilled up to an angle of 60°, anything more than this is costly and could only be justified if it increases productivity[5].

Directional wells are categorized into four groups depending on their geometries. The geometry of the well is designed specifically for the issues encountered when drilling the well, depending on the situation. Typically directional wells are drilled to a certain predetermined depth and then guided toward a desired direction. This predetermined depth is commonly referred to as the kick-off-point (KOP).

Fig. 1.1 is typical Type 1 geometry well, commonly called a "build and hold". First a vertical section is drilled to the kick-off-point; once the bit has been kicked off it follows a build section - the curved part of the well. Finally after a certain angle is achieved the well is drilled at that angle, this is the hold section. The Type 1 well is the most commonly used geometry because of its simplicity. This shape is preferred when a large horizontal displacement is desired and at a shallow target depth.

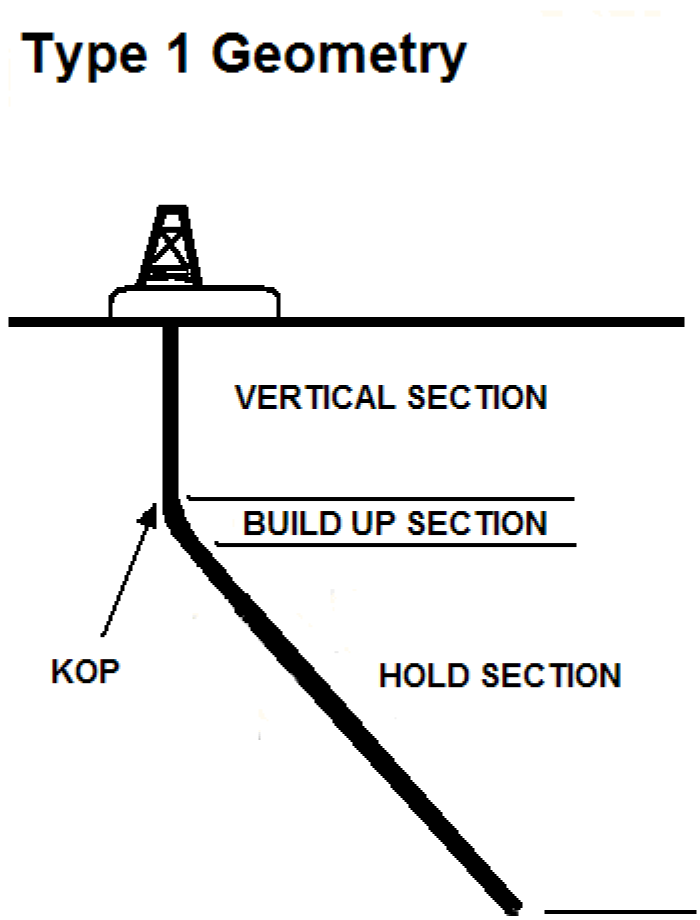

Fig. 1.1 – A typical geometry for a Type 1 well

The second geometry is the Type 2 geometry; popularly coined “build, hold and drop.” The typical shape is shown in **Fig 1.2**; this configuration contains a build section, a hold section and a drop section. The difference between the Type 1 and Type 2 geometry is the drop section. **Fig 1.2** shows the well returning to vertical at the target depth, this is not always the case. The Type 2 geometry may be desired by the driller if an impenetrable spot is encountered or if an area should be avoided. Generally this type is used when a small horizontal displacement and deep target depth is desired.

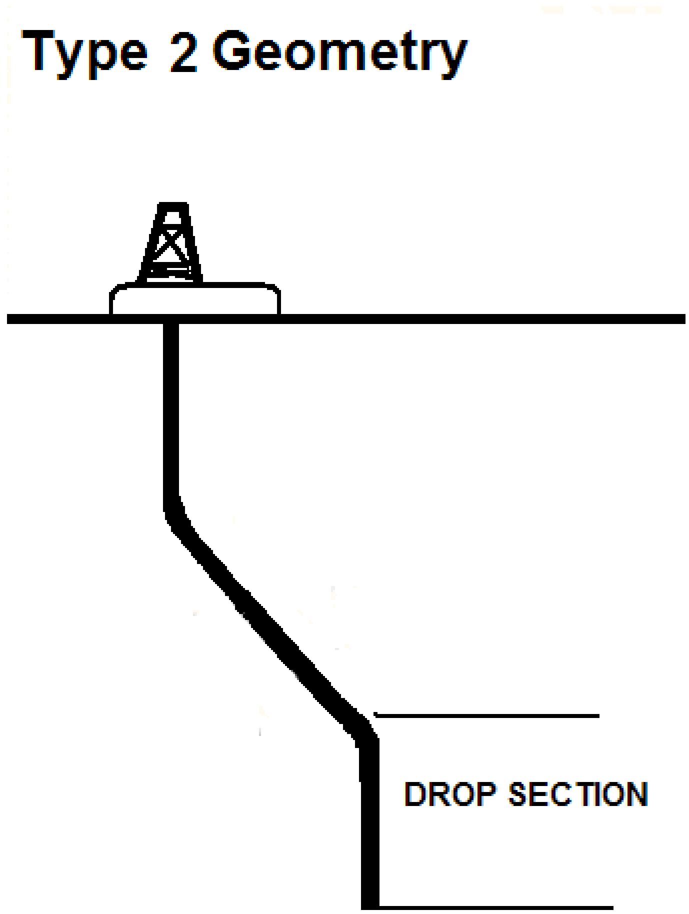

Fig. 1.2 – The Type 2 wellbore geometry contains a kick off point and a drop down point

The third geometry type, Type 3 is called the "continuous build." This geometry never has a hold section; it is continuously built to the target depth. A common use of Type 3 geometry is to drill around salt domes. Usually the well is drilled vertically to a depth above the reservoir and then it is kicked off towards the reservoir at the flank of the salt dome. Another popular application of the Type 3 geometry is sidetracking. The continuous build frequently has a deep KOP. **Fig. 1.3** illustrates the deep KOP of this type of geometry**.**

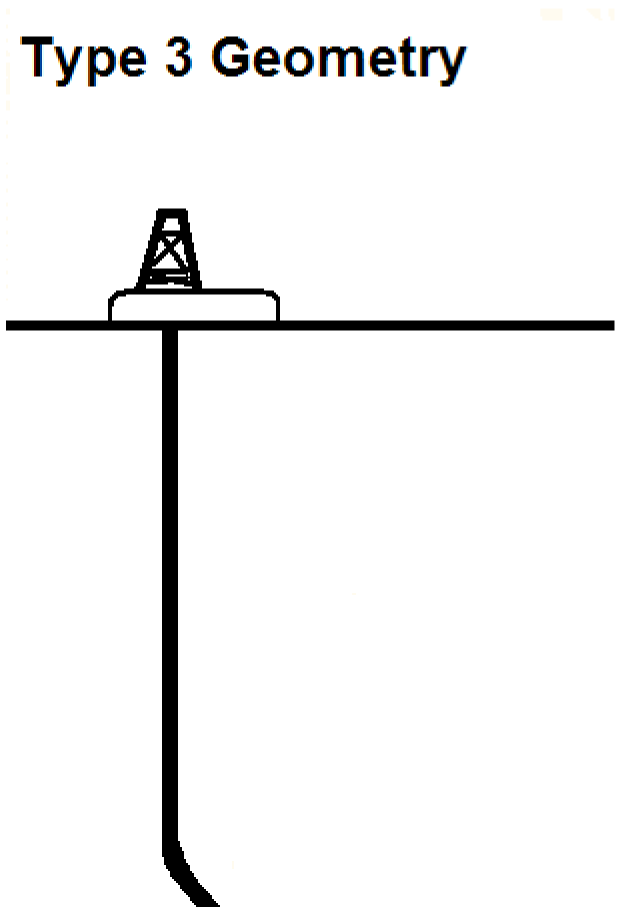

Fig. 1.3 – Type 3 geometry is typically used to drill salt domes and sidetrack

A special type of deviated well, the fourth type, is the horizontal well. It can be classified as Type 1 geometry because it has a build-up section, to 90 degrees, and a hold section, horizontal, but here it will have its own classification. Horizontal wells are usually drilled as development wells and are used to increase productivity. The horizontal section of the well is run within and parallel to the producing zone thereby increasing the length inside the pay zone. There are three classifications to horizontal wells, short, medium and long radius. **Table 1.1** shows the characteristics of the three classifications of horizontal wells.

Table 1.1 – Characteristics of the three classifications of horizontal wells[3,6]

Horizontal Wells	Turn Radius *ft*	Build Rate *°/100ft*	Horizontal Extension *ft*
Short	20 to 60	100 to 1500	100 to 800
Medium	70 to 800	8 to 50	1500 to 3000
Long	1000 to 3000	2 to 6	2000 to 5000

1.2 Well Control

Well control considerations are different in directional wells than in vertical wells because of the difference between their measured depths and vertical depths. Deviated wells will encounter a lower formation pressure and strength due to the lower overburden pressure and the effect of the mud column will be less when the measured length is compared to a similar vertical hole. For holes with the same vertical depth, deviated wells will have a higher pump pressure and slightly higher dynamic bottom hole pressure (BHP) circulating because of the greater length of the wellbore.[5]

Whether the well being drilled is vertical or directional, taking a kick that could lead to blowouts is always a concern.

1.3 Kicks

A "kick" is an unexpected entry of formation fluids in the wellbore of sufficient quantity to require shutting in the well.[7] This occurs when bottom hole pressure (BHP) falls below the formation pressure where the formation has sufficient permeability to sustain the flow of fluid into the wellbore. A drop in BHP is caused by any number of things. Common causes are failure to keep the hole full of mud, swabbing, lost circulation, and insufficient density of drilling fluid. Kicks that are improperly controlled can easily escalate into blowouts.

1.4 Blowouts

Blowouts are a direct result of failure to control a kick in a well. Personal injury and death of personnel can result from a blowout as well as financial loss to everyone involved. Blowouts are classified into two classes, and neither case is good for the operator. The two classifications of blowouts are: 1) Surface Blowouts and 2) Underground Blowouts.

In offshore operations surface blowouts can be further divided into surface and subsurface blowouts. This differentiation does not occur with onshore blowouts.

Surface blowouts gain a lot of attention and frequently catch the eye of the media because the dangers and the destructive nature of a blowout are easily seen and the ramifications of a blowout become apparent. The ominous sight of oil and gas spewing everywhere and fire flames high into the sky commands a lot of respect; it is undoubtedly an incredible sight. Surface and subsurface blowouts both originate at a permeable formation down hole where an influx of formation fluid occurs. In surface blowouts the fluids exit at the rig floor, while subsurface blowouts exit at the seafloor. A subsurface blowout may not be apparent at the surface in deep waters because the currents and depth disperse the gas and fluid escaping from the well. In shallow waters its effect is easily noticed by the rig above and at times the rig is put into peril. If shallow water currents are not present or are weak, the gas escaping the seafloor will cause a loss of buoyancy and will cause a loss of stability for the rig directly above.

Underground blowouts (UGB) occur when formation fluids invade the wellbore and flow into other permeable zone(s) with lower pressure(s). These types of blowouts are not covered by the evening news and many people are unaware of their existence. Their apparent lackluster nature falsely leads one to underestimate its potential power. The pressures involved are usually small and operators do not take then as seriously as they should. UGB occur 1.5 times more frequently than surface and subsurface blowouts combined and they can escalate into as dangerous and costly situations. The UGB can be the most difficult to control, even more so than surface blowouts and they can be the most dangerous and destructive type of blowout.[8] The difficulty with UGB is their conditions are hidden and can evade analysis; neither the influx volume nor the composition is usually known and the conditions of the wellbore and tubular condition are not readily known.

UGB can broach to the surface and become surface or subsurface blowout if they occur within 3000-4000 ft from the surface. The fractures propagates outside the casing reaching to the surface.[8,9] This situation is difficult to alleviate and should be avoided if possible.

Over the years methods have been devised to contain blowouts. The next section describes a few types of containment.

1.5 Blowout Containment

Preventing blowouts are a major concern in drilling and completion operations. Many methods have been developed to kill a blowing well; some methods are more effective than others in certain circumstances. Every blowout is different and the procedure to kill them is particular to each case. Blowout containment is broken down into two categories: 1) Surface intervention and 2) Relief well intervention.

Surface intervention requires action to be taken at the exit point of the blowout - specifically at the wellhead. If access to the well head is impractical or virtually impossible, a relief well has to be drilled. A relief well aims to stop the blowout at a subsurface point of the blowing well. The placement of the relief well should be at a safe distance upwind to the blowout and are usually the last option due to the time required to drill the well.

Capping techniques are a type of surface operation of three basic procedures: 1) extinguish the fire, 2) cap the well and 3) kill the well. If hydrogen sulfide is present, it is inadvisable to put out the fire since it poses less of a health concern when it is flared. After this issue is resolved a capping stack is installed and flow is diverted from the well[8]. At this point dense fluid is pumped into the well to regain control. This method only applies to land operations since the blowout has to reach the surface and access to the seafloor wellhead in offshore operation is limited.

Momentum kill or bullheading is another form of surface intervention. If the drillpipe is still in the hole, then momentum kill can be performed. If it is not present, then one has to be snubbed down using a snubbing unit[10]. The string does not need to be all the way to the bottom of the well, since the principle behind momentum kill is to circulate a kill fluid with a high enough momentum to stop and push back the formation fluid migrating up the wellbore. This method is employed often when sour gas containing hydrogen sulfide is associated with blowout. A drawback to this method is the end result could ruin the formation or cause an underground blowout.

Relief wells are used when killing from the surface is impractical or impossible. Early relief wells were drilled into the blowing formations near to the blowing well and were made to produce at high rates as an attempt to relieve the pressure in the blowing well.[11] Water was later employed to flood the flowing formation to arrest the flow of hydrocarbons to the blowing well. With the advent of directional drilling and electromagnetic tools, intersecting the blowing wellbore is possible and is the most practical and effective way to kill a well utilizing a relief well.

1.6 Dynamic Kill

The dynamic kill is one of the oldest and widely used intervention method and was developed to gain more control of the intervention. It can be done as a surface intervention or as a relief-well intervention.[8,12] The basic theory of the dynamic kill is to inject a kill fluid at a rate that will generate sufficient frictional pressure to stop the influx of formation fluid.[8] One requirement of the dynamic kill method is the hydrostatic pressure exerted by the kill fluid at static conditions cannot be greater than the reservoir pressure; therefore seawater is usually used as the kill fluid. The dynamic kill method is intended as an intermediate step in the well control procedure rather than a single-step solution procedure. After the influx has stopped a heavier weight fluid has to be circulated to statically control the well.

When everything else fails, "gunk" could be used to contain the blowout. Gunk is a mixture of cement, bentonite and diesel fuel. When it is mixed with water-based mud it forms a thick gelatin plug. [13] The major drawback to this last ditch effort is if the plug is spotted wrong, it will be impossible to recover the well.

2. BACKGROUND

2.1 Proposal

In 2002 the Minerals Management Services funded Texas A & M University, College Station, and Cherokee Offshore, to study blowout containment in ultra-deep-waters. [14] Nothing had been written previously discussing the blowout considerations in ultradeep water. In 1991 Neal Adams Firefighters Inc. published a report dealing with offshore blowout containment, but at the time of publication, wells greater than 5000 feet were thought to be impractical and the technology was unavailable for such a great endeavor. Neal Adams report, *DEA 63 Report: Floating Vessel Blowout Control*, focuses on offshore well control in water depths of 300 to 1500 feet.[10] Since then drilling technology has improved and water depths greater than 1500 feet are commonplace and water depths of 5000 feet are becoming more routine.

The project from the Mineral Management Services consisted of several goals. One of them included researching bridging tendencies in ultradeep water wells in the Gulf of Mexico. Many times a well will bridge or the open hole will collapse and will kill the well. A simulator was developed to model these tendencies. Another goal is to develop a simulator to model dynamic kills in ultradeep waters. This thesis is part of the latter goal. At the time of the proposal there were no simulator developed to model blowouts in ultradeep water with dual density modeling capabilities and the ability to predict bridging of a blowing well in the Gulf of Mexico.

In 2004 a preliminary dynamic-kill simulator was developed by Dr. Ray T. Oskarsen which he named COMASim. [15] This program was validated theoretically using examples from Advanced Well Control: SPE Textbook Series Vol. 10. [16] The available case histories of actual blowouts were lacking in data or were unusual cases and could not be used to validate the simulator.

2.2 COMASim

As previously mentioned no simulator has been designed to model ultra-deepwater blowouts, dynamic kills and dual density models. Several simulators have been developed that simulate blowouts and dynamic kills. These simulators include OLGA-WELL-KILL, DynX, Sidekick, and one developed by Otto Santos for Petrobras. [17]

OLGA-WELL-KILL is a state-of-the-art Norwegian simulator, not available for use in the industry and is not specifically built for ultra-deepwater. [18] DynX is an Excel spreadsheet program developed at Louisiana State University. It takes into account sonic flow gas/mud mixtures and has the capabilities to model directional wells, off-bottom kills and underground blowouts. [19] Sidekick is a kick simulator and it can be used to simulate dynamic kills for gas well blowouts. The drawback to this simulator is the fact that it cannot simulate circulation through a relief well. [20] Otto Santos with Petrobras constructed a FORTRAN program that studies blowouts in ultra-deepwater with transient capabilities. [8]

COMASim attempts to combine the practical functions of these simulators into one simulator that has ultra-deepwater capabilities. Specifically, COMASim is a Java based program that can be used as a web-based application or as a stand alone program. [15] One of the best features is its simplicity and user friendliness. It contains four main sections; input data, estimate of initial blowing condition, calculation of minimum kill rate, and graphical output of results, **Fig 2.1**. COMASim has capabilities for gas and liquid reservoirs. The application of the dynamic kill can be applied through a relief well or through the drillstring of the blowing well. The simulator can also simulate Newtonian and non-Newtonian kill fluid and can model the blowing well flowing though the annulus and though the drillpipe. The program can simulate dynamic kills for surface, subsurface, and underground blowouts.

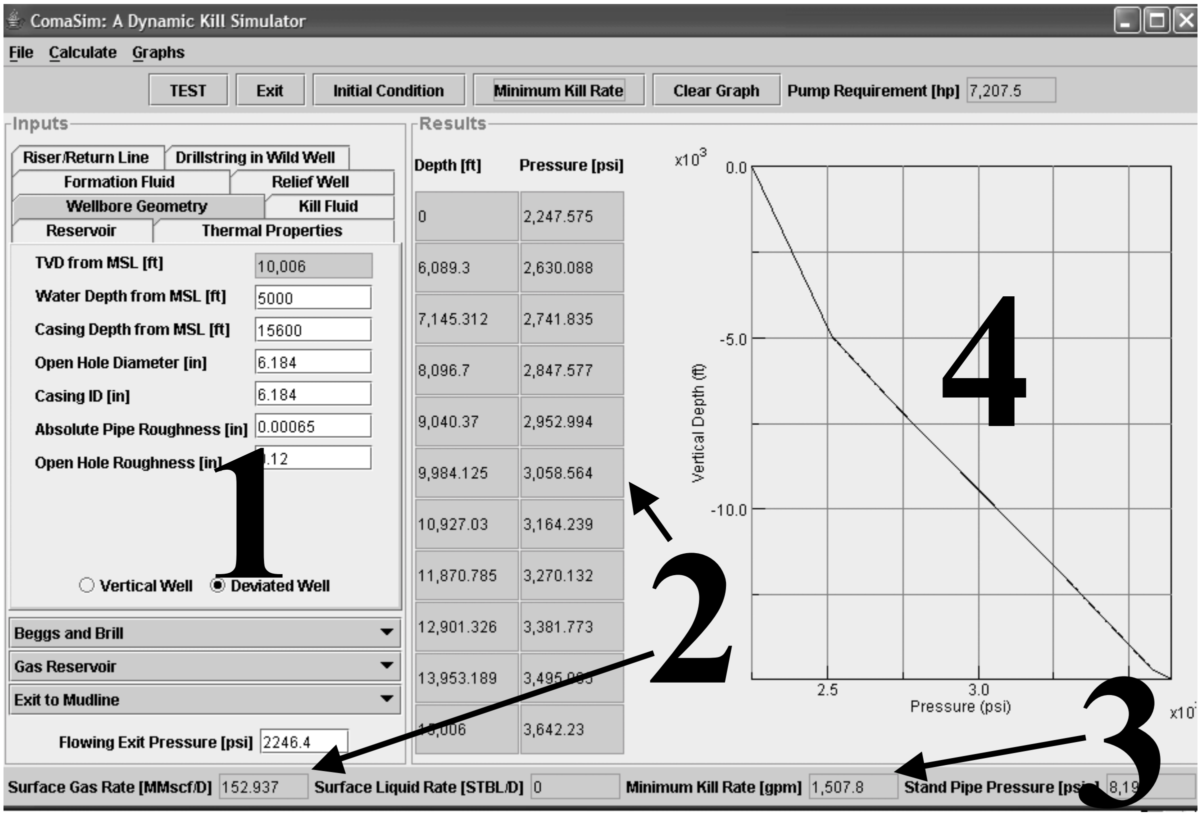

Fig. 2.1 – 1) Input section 2) Initial blowing conditions 3) Minimum kill rate 4) Graphical output

2.3 Thesis Objectives

Currently COMASim is a valid simulator, but it has limitations since only one version of it had been developed. This first version can only simulate blowouts and dynamic kill calculations in vertical wells. Currently ultradeep water wells are drilled vertically, but as these depths become routine, the geometries will be more complex. For the simulator to be robust and be meaningful in the industry, it has to be kept current with technology. The objective to this study is to add directional well capabilities to COMASim and to run several scenarios with different wellbore geometries observing their effects.

3. DEVELOPMENT OF COMASIM V 1.0

The first version of COMASim was simple and efficient, but not robust. It lacked the capabilities to model directional wells. As technology advances, directional wells will commonly be drilled in ultra-deepwater environments. Therefore the simulator has to keep up with the technological needs to handle these cases. The main objective to making improvements to the original COMASim was to keep the original framework and try to keep the program looking and feeling the same. The graphical interface was altered to include only the essential elements. Additional modifications include the ability to read survey data, save simulations results and model directional wells in ultradeep water.

3.1 Modifications to the Graphical Interface

The beauty of COMASim is its simplicity; this was preserved when developing the modifications. Only essential modifications were made to the graphical interface of COMASim. Later versions may include user options to change the display or alter its appearance; this was not done with this version. The new version needed a way to calculate minimum kill-rate requirements and initial conditions taking into account different wellbore geometries. The preliminary idea was to add a new input field for the user to directly add the total measured depth of the wellbore. After further inspection one would see that this would result in an inaccurate representation of geometry. Reading the depths from a depth file is the only practical solution available.

The user has two options to choose from when deciding the geometry, vertical or directional. Two radio buttons at the bottom of the screen under the *Wellbore Geometry* tab in the *Input* side of the simulator's main screen lets the user decide what geometry they want. If the vertical button is selected the program runs the simulations similar to the original COMASim. If the directional button is selected a *File Dialog Box* appears and allows the user to select the file that contains the desired depth data.

Since a new variable, measured depth, is introduced to the program, output graphs have to be made to include this parameter. Under the Graphs menu in the Menu bar, five new graphs were added. *Measured Depth vs. Pressure, Measured Depth vs. Temperature, Measured Depth vs. Velocity, Measured Depth vs. Liquid Hold Up* and *Wellbore Trajectory* **Fig. 3.1 – 3.3**. After the computations are calculated, the results are shown on these graphs.

Pressure vs Depth

Results

Measured Depth [ft]	Pressure
0	2,247.575
6,089.3	2,630.088
7,178.6	2,741.835
8,267.9	2,847.577
9,357.2	2,952.994
10,446.5	3,058.564
11,535.8	3,164.239
12,625.1	3,270.132
13,714.4	3,381.773
14,803.7	3,495.065
15,893	3,642.23

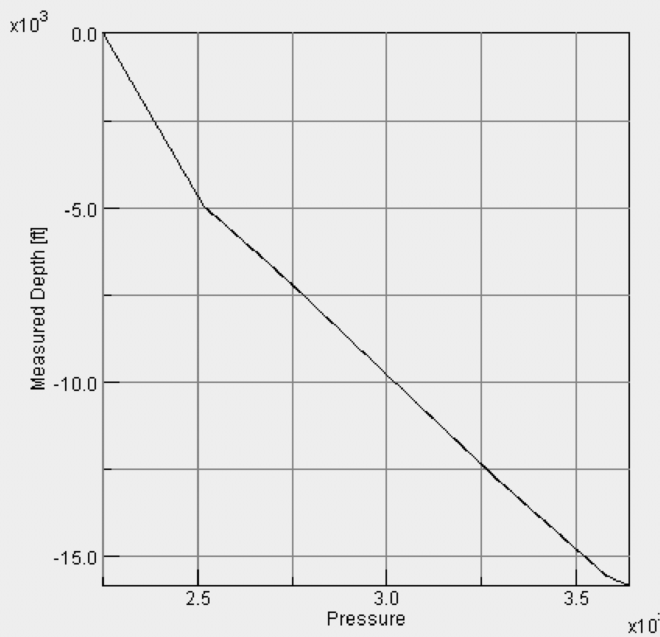

Fig. 3.1 – Measured depth vs pressure

Temperature vs Depth

Results

Measured Depth [ft]	Temperature [F]
0	120
6,089.3	126.942
7,178.6	133.885
8,267.9	140.827
9,357.2	147.769
10,446.5	154.712
11,535.8	161.654
12,625.1	168.597
13,714.4	175.539
14,803.7	182.481
15,893	189.424

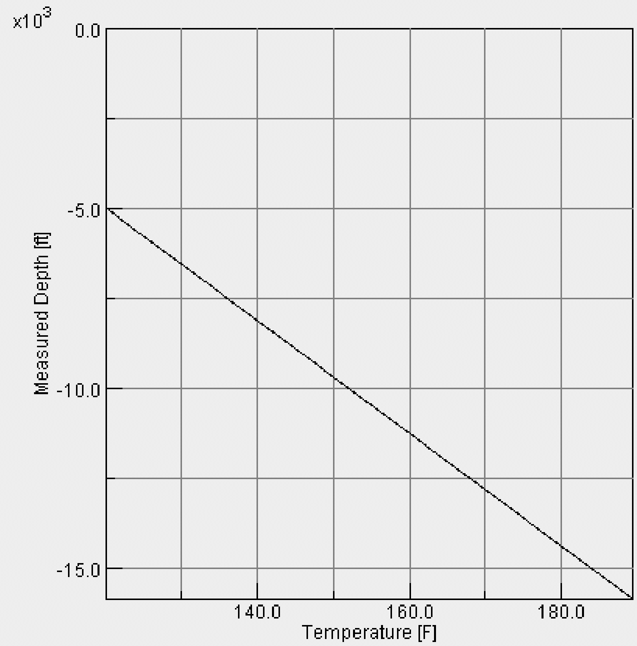

Fig 3.2 – Measured depth vs temperature

Wellbore Trajectory

Results

Vertical Depth [ft]	Departure Length [ft]
0	0
6,089.3	0
7,145.312	220.174
8,096.7	748.755
9,040.37	1,292.01
9,984.125	1,835.133
10,927.03	2,379.776
11,870.785	2,922.87
12,901.326	3,251.808
13,953.189	3,525.787
15,006	3,796.116

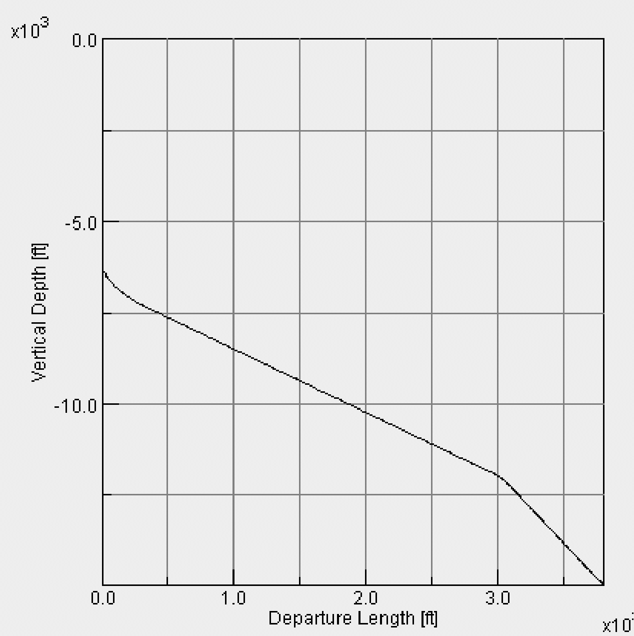

Fig. 3.3 – Wellbore trajectory

3.2 Depth File

The depth file to be used by COMASim 1.0 has to meet some criteria so that the simulator can read it. Data from a spreadsheet program can be exported into tab delimited format but the vertical depths have to be on the left column and measured depth on the right. If the data is from an offshore well, the depths in the file should start from the mudline rather than sea level. The only information in the depth file should be depths; title, units and anything else is prohibited. COMASim will check to see if the data are valid once the data are read. These checks make sure that measured depth is equal to or larger than vertical depth, depths are in increasing order and geometry is valid.

3.3 Modifications to the Depth Acquisition

Measured depth in deviated wells is greater than measured depth in vertical wells with the same vertical depth. Vertical depth is the vertical distance from a point in the well (usually the current or final depth) to a point at the surface, usually the elevation of the rotary kelly bushing (RKB). This is one of two primary depth measurements used by the drillers, the other being measured depth.[21] Measured depth is the actual length of the wellbore. This is measured by measuring the lengths of the individual joints of drill pipe and drill collars and other drillstring elements and adding them together. The differences between the depths are seen in **Fig 3.4**.

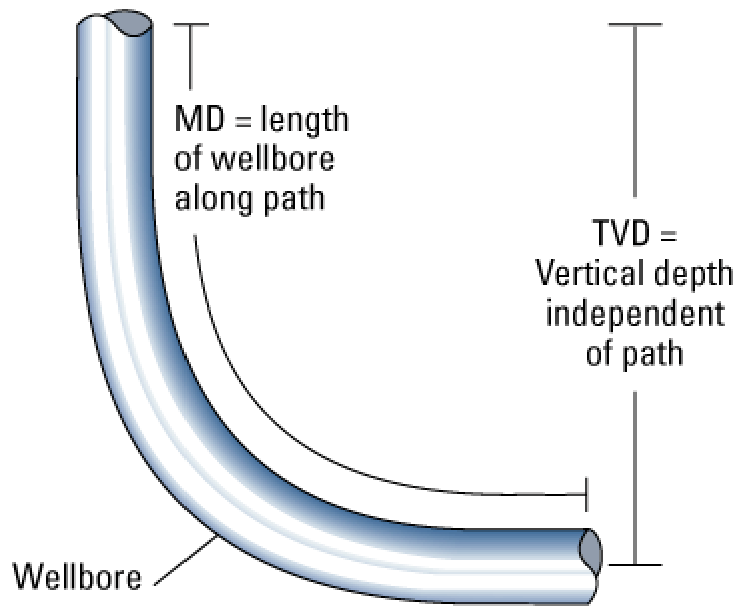

Fig. 3.4 – Diagram of vertical depth and measured depth[21]

The new simulator is structured to use two arrays for depths; previously only one array was used for depth calculations - vertical depth. Calculations of the array were done from the user input of total vertical depth. The depth was divided into 500 elements of equal depth. This algorithm is good for wells with vertical geometry but for directional wells this is inadequate. The new version uses two arrays, one for vertical depth and one for measured depth. The problem arose that by simply adding a text field for measured depth input by the user and dividing it into 500 elements would only result in a straight hole at an angle from the surface. The only way to resolve this issue was to have the depth directly read from a file.

The depth data read from COMASim 1.0 assumes that the data are taken from the mudline in offshore operations and sea level in land operations. The data are read into the simulator and necessary modifications are performed to add water depth, if necessary. If the blowout occurs at the mudline, COMASim will remake the depth array to match the user's requests.

Depth data are taken at random intervals; therefore adjustments need to be made to make these depths of equal interval lengths to facilitate the computations of the simulator. The total measured depth is divided into 500 equal elements rather than vertical depth, because in the case of a horizontal well, one foot of elevation on vertical depth could potentially cause a very large corresponding segment in horizontal length. This would cause a significance loss in accuracy and leads to a source of error. The vertical depths are then adjusted to match their corresponding measured depth. Linear interpolation is used between two known depth points, **Eqn.3.1**.

$$VD_i = SVD_i + (SVD_i - SVD_{i+1})\left(\frac{MD_{calc} - MD_i}{MD_{i+1} - MD_i}\right) \qquad 3.1$$

The depth array is calculated from the top of the well to the bottom and the vertical depth is made by interpolating from two known vertical depth points in the depth file, **Fig 3.5**. The depth arrays serve as a basis for the calculations needed to reach the calculation for the minimum kill rate required to kill the well and the initial conditions, because pressures and temperatures are dependent on depth.

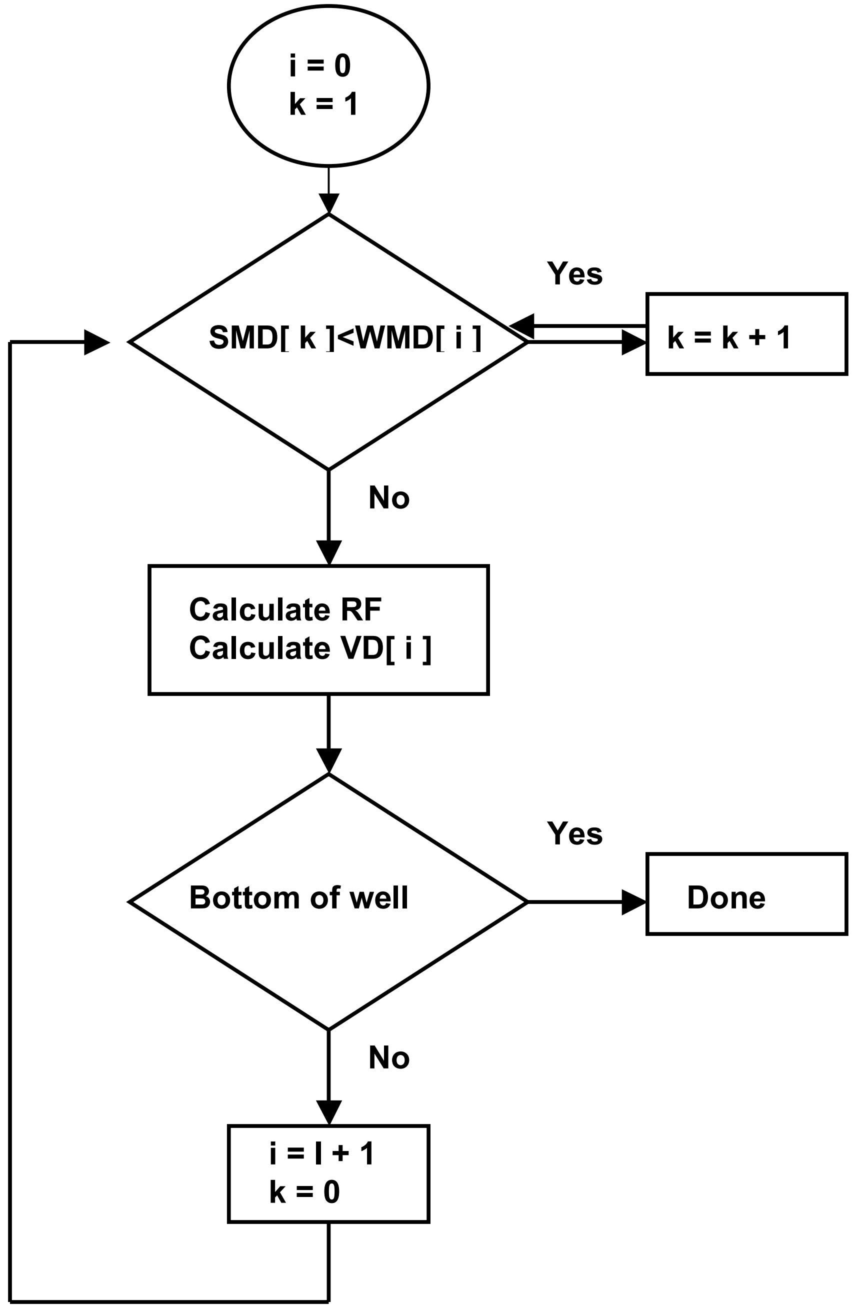

Fig. 3.5 – Flow chart for calculating vertical depth

3.4 Modification to the Pressure Models

The depths obtained are essential to the calculated pressures in the wellbore; for example the overburden pressure comes from the water depth and the type of rock in consideration and hydrostatic pressure is the pressure exerted buy the weight of the fluid due to gravity; this is also a function of vertical depth. When a well is blowing out, time is a crucial issue. Having a simulator that requires every detail of the well to be input to make an accurate estimate may be a waste of time when you can use a simulator that does not require much information but gives results that are accurate to a degree of tolerance. This was considered during the development of the original COMASim.

The basic pressure equation has three terms associated with it, 1) frictional pressure, 2) acceleration pressure and 3) elevation or hydrostatic pressure. In the original simulator three multiphase flow models are available to calculate the pressure gradients. These models were kept in the newer version, because they are versatile and commonly used in the industry.

The general pressure gradient equation can be used with any fluid and with any pipe inclination angle.

$$\frac{dp}{dL} = \frac{\rho g \sin\theta}{g_c} + \frac{f\rho v^2}{2g_c d} + \frac{\rho v}{g_c}\left(\frac{dv}{dL}\right) \quad \text{......................................3.2}$$

If the angle from vertical is used, the equation becomes,

$$\frac{dp}{dL} = \frac{\rho g \cos\phi}{g_c} + \frac{f\rho v^2}{2g_c d} + \frac{\rho v}{g_c}\left(\frac{dv}{dL}\right) \quad \text{..................................3.3}$$

Generally speaking this equation is the sum of the pressure gradients, Eqn 3.4.

$$\left(\frac{dp}{dL}\right)_{total} = \left(\frac{dp}{dL}\right)_{elevation} + \left(\frac{dp}{dL}\right)_{friction} + \left(\frac{dp}{dL}\right)_{acceleration} \quad \ldots\ldots\ldots\ldots\ldots 3.4$$

In oil wells the density of the fluid is much greater than in gas wells and therefore more percentage of pressure is in the hydrostatic component. In gas wells the density is smaller but travels at a higher velocity and therefore creates more frictional pressure loss in the tubing, **Table 3.1**.

Table 3.1 – Pressure contributions as a percentage in tubing[22]

Component	**Percent of Total Δp** Oil Wells	**Percent of Total Δp** Gas Wells
Elevation (Hydrostatic)	70-90	20-50
Friction	10-30	30-60
Acceleration	0-10	0-10

3.5 Hydrostatic Pressure

Hydrostatic pressure also is elevation pressure and it is dependent on the density of the fluid and the vertical depth. When a well is filled with a fluid, the fluid imposes a force against the wellbore due to its weight. A denser fluid will impose more pressure per length than a lighter fluid will. Measured depth does not play a role in this calculation, therefore in horizontal sections of pipe the hydrostatic pressure remains the same.

3.6 Acceleration Pressure

This pressure is due to kinetic energy change. This term has been completely ignored by some investigators and ignored in some flow patterns by others. This term usually comprises less than 10 of the total pressure drop; many times it is insignificant. If compressed gas is present in the wellbore, the acceleration term may become significant.

3.7 Frictional Pressure

Frictional pressure accounts for most of the pressure in gas wells. This pressure is caused by the resistance of flow imposed by the surface roughness of the conduit through which it flows through. It is dependent on the velocity of the fluid and of the friction factor of the surface the fluid is flowing through, the diameter of the conduit and lastly the density of the fluid. In rough pipe or in open hole sections the friction factor can be high, which results in a larger frictional pressure term. Higher velocities also will cause an increase in frictional pressure.

3.8 Development of Pressure Calculations

In the development of the original simulator, depth was a single array and measured depth was assumed to be the same value as vertical depth. Since directional and horizontal wells do not follow the same geometry, a new algorithm had to be developed to ameliorate this problem. In the previous section it was explained that measured depth and vertical depth were read from a file and placed into two arrays. These arrays facilitate finding the pressure profile of the wellbore. Acceleration and frictional pressure depend on the measured length of the well as explained above, while hydrostatic pressure is best modeled with vertical depth. Each element has these three terms and total pressure is the sum of these terms. Therefore three separate arrays were needed to contain these components. Depending on what multiphase flow model was chosen the pressure gradient for each component was calculated and assigned to its array. The total pressure is calculated by adding the elements of the three separate arrays.

3.9 The Multiphase Models

The three multiphase models included in COMASim 1.0 are Duns and Ros (1962), Hagedorn and Brown (1965), and Beggs and Brill (1973). These are empirical correlations used to obtain pressure gradients in multiphase flow though a pipe. In the industry, these models are used frequently and their results are trusted.

3.9.1 Duns and Ros Method

The Duns and Ros correlation is developed for vertical flow of gas and liquid mixtures in wells. This correlation is applicable over a wide range of oil and gas mixtures and flow regimes. The intended use is with dry oil/gas mixtures but it can be applied to wet mixtures with a suitable correction. [23]

3.9.2 Hagedorn and Brown Method

This correlation was developed using data obtained from a 1500-ft vertical well. Tubing size ranged from 1 – 2 in. diameter in this experiment along with 5 fluid types. The correlation developed is independent of flow patterns. With this model, over prediction of pressure is caused by using tubing larger than 1.5 in. Over prediction of pressure also occurs with heavier oils and under prediction occurs with lighter oils. [23]

3.9.3 Beggs and Brill Method

The Beggs and Brill correlation was developed for tubing strings in inclined wells and pipelines for hilly terrain. A wide range of parameters were tested. This method applies to flow in a pipe at any angle of inclination, including downward flow. In vertical wells this method is known to over predict pressure gradients. It is recommended using this correlation in deviated wells and Hagedorn and Brown for vertical wells. [23]

4. SIMULATIONS AND RESULTS

Twenty-one cases were run with varying well geometries; six consisting of Type 1, nine of Type 2, three of Type 3 and three horizontal. The Beggs and Brill multiphase flow correlation was used in these simulations because it is more appropriate in directional wells than the Hagendorn and Brown or Duns and Ros correlations. Other reservoir properties and tubular properties were kept constant for all of the runs. **Table 4.1** lists the properties that were constant for all runs.

Table 4.1 – Simulation parameters that remain constant

Reservoir Properties		
Average Reservoir Pressure	7176	psia
Permeability	10	md
Reservoir Drainage Area	10000	acres
Reservoir Height	100	ft
Gas/Liquid Ratio	100	scf/STB
Water Cut	50	%
Gas Reservoir		
Exit to Mudline		
Temperature Properties		
Geothermal Gradient	1.5	°F/100 ft
Exit Temperature of Fluid	120	°F
Specific Heat at Constant Volume	0.414	btu/lbm-f
Specific Heat at Constant Pressure	0.537	btu/lbm-f
Straight Line Model		
Wellbore Geometry		
Hole Diameter	6.184	in
Casing ID	6.184	in
Absolute Pipe Roughness	0.00065	in
Open Hole Roughness	0.12	in
Riser Properties		
Riser Roughness	0.00065	in
Formation Fluid Properties		
Gas Specific Gravity	0.6	
H2S, CO2, N2 Concentration	0,0,0	%
Oil Api	35	°API
Bubble Point Pressure	2634.7	psia
Water Specific Gravity	1.02	
Water Salinity	50000	ppm

Build up rate (BUR), KOP, hold length, departure angle and drop off rate (DOR) were changed in these runs; these parameters are listed in **Table 4.2** along with other well geometry information.

Table 4.2 – Parameters that are changed with each simulation

	KOP_1	BUR	θ_1	Length of Hold	KOP_2	DOR	θ_2
	feet	*deg/100ft*	*deg*	*feet*	*feet*	*deg/100ft*	*deg*
Type 1							
	9000	1	30	3620	-	-	-
BUR	9000	5	30	6267	-	-	-
	9000	10	30	6597	-	-	-
	6000	2	30	8718	-	-	-
KOP	10000	2	30	4120	-	-	-
	13000	2	30	656	-	-	-
Type 2							
Length	6000	2	30	667	8167	2	30
Of	6000	2	30	4122	11622	2	30
Hold	6000	2	30	6489	13989	2	30
	6000	2	30	5280	12780	1	30
DOR	6000	2	30	5280	12780	5	30
	6000	2	30	5280	12780	10	30
	6000	2	30	5280	12780	10	5
θ_2	6000	2	30	5280	12780	10	15
	6000	2	30	5280	12780	10	25
Type 3							
	9500	0.5	60	-	-	-	-
	11000	1	60	-	-	-	-
	14000	5	60	-	-	-	-
Horizontal							
LONG	7100	2	90	4000	-	-	-
MEDIUM	9700	2	90	2000	-	-	-
SHORT	10000	2	90	500	-	-	-

Six cases were run using Type 1 geometry. The first simulation had varying BUR. Three different BUR were chosen, 1, 5 and 10°/100ft. As with all the simulations total vertical depth (TVD) was kept at 15,000 ft from sea level. The BUR of 5°/100ft and 10°/100ft had very similar wellbore geometry, **Fig. 4.1**. For all cases the casing was set within 100 ft from the total measured depth assuming the blowout occurred after casing was set and drilling had commenced.

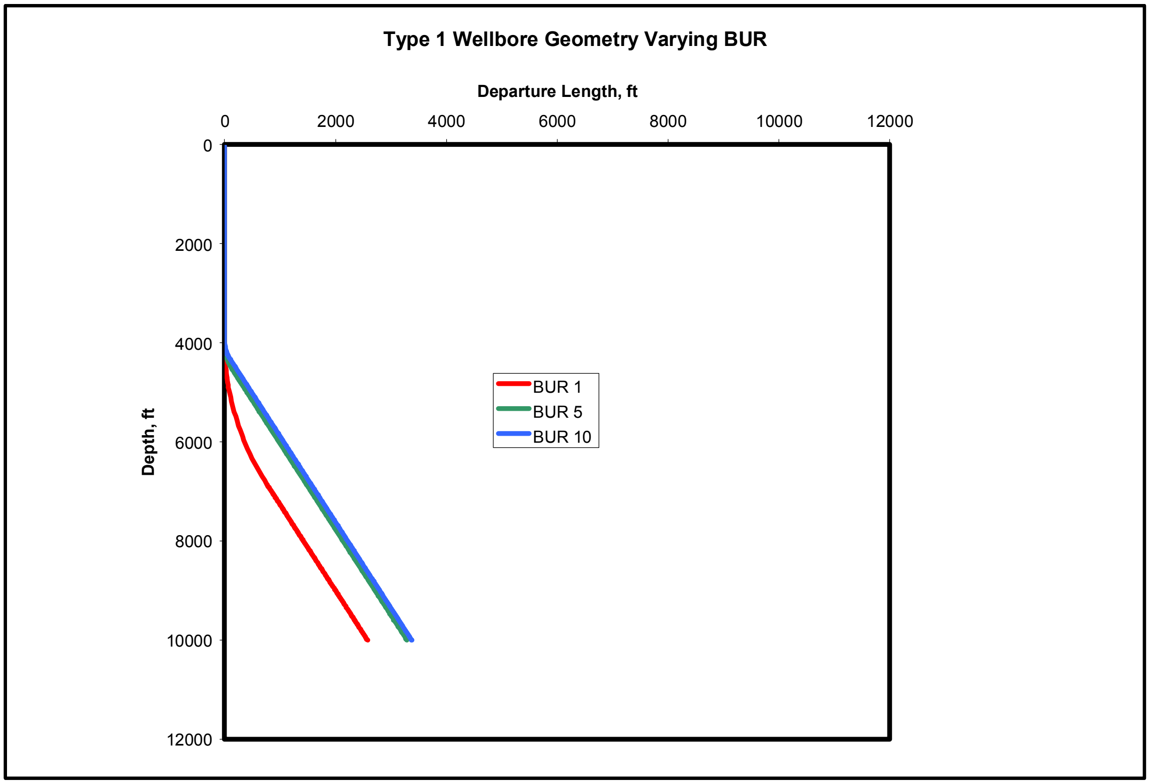

Fig. 4.1 – Wellbore geometries for varying BUR

From **Fig. 4.2** minimum kill rate required to stop the flow of formation fluids decreases with increasing BUR. All three wellbore have the same vertical depth; the only difference is in the measured depth. A BUR of 10°/100ft engenders a longer measured depth than the other rates. In all cases the hydrostatic pressure is constant because of the same vertical depth. More frictional pressure is created with a longer measured depth; therefore, lower rates are needed to kill the well. From the graph the horsepower requirements and standpipe pressure for the 5 and 10°/100ft did not show much change because the geometry of these wells is quite similar. A 1°/100ft BUR required a kill rate of almost 1585 gpm to kill the well while a 5°/100ft required a rate of 1565 gpm.

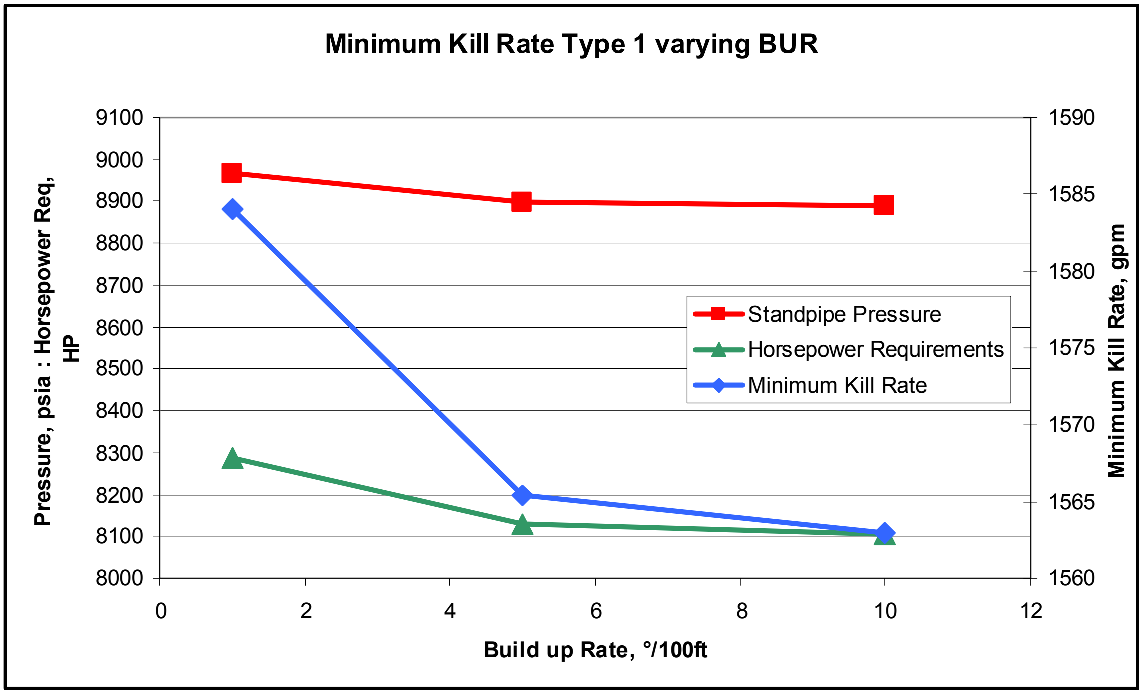

Fig. 4.2 – Minimum kill rate decreases with increasing BUR

The second Type 1 simulation varies KOP. Three KOP depths were selected to test its effect of minimum kill rate requirements, 1000 ft, 5000 ft and 8000 ft from the mudline. A 30 degree build angle with a 2°/100ft BUR was constant for these three simulations. From the wellbore geometries shown in **Fig 4.3**, the well with 1000 ft KOP has the longest departure length from vertical and has the longer length.

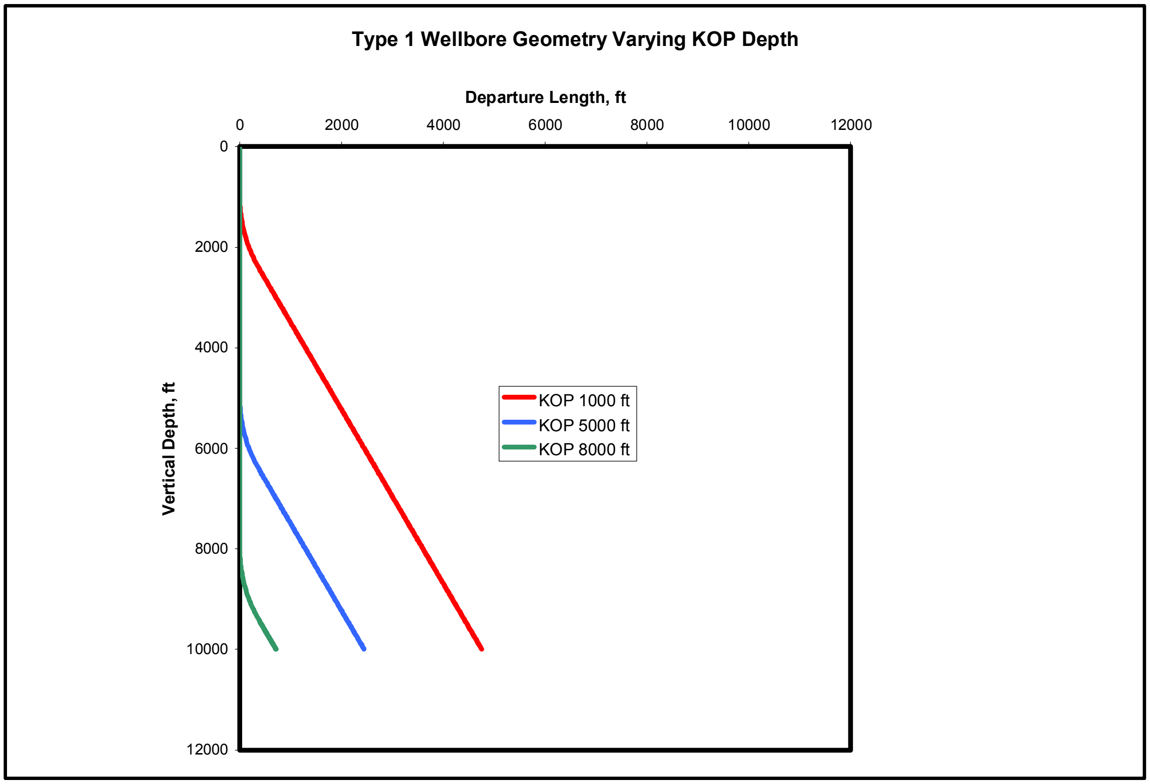

Fig. 4.3 – Wellbore geometry for varying KOP depths in Type 1 geometry

A KOP at 8000 ft requires a kill rate of 1610 gpm seawater to stop the inflow of fluid into the wellbore. **Fig 4.4** shows almost a 90 gpm higher rate requirement at a 8000 ft KOP than at 1000ft. KOP. The decrease in the required kill rate is attributed to the longer measured length causing more frictional pressure to help kill the well. Between a KOP of 5000 and 8000 the minimum required kill rate increased by 26gpm.

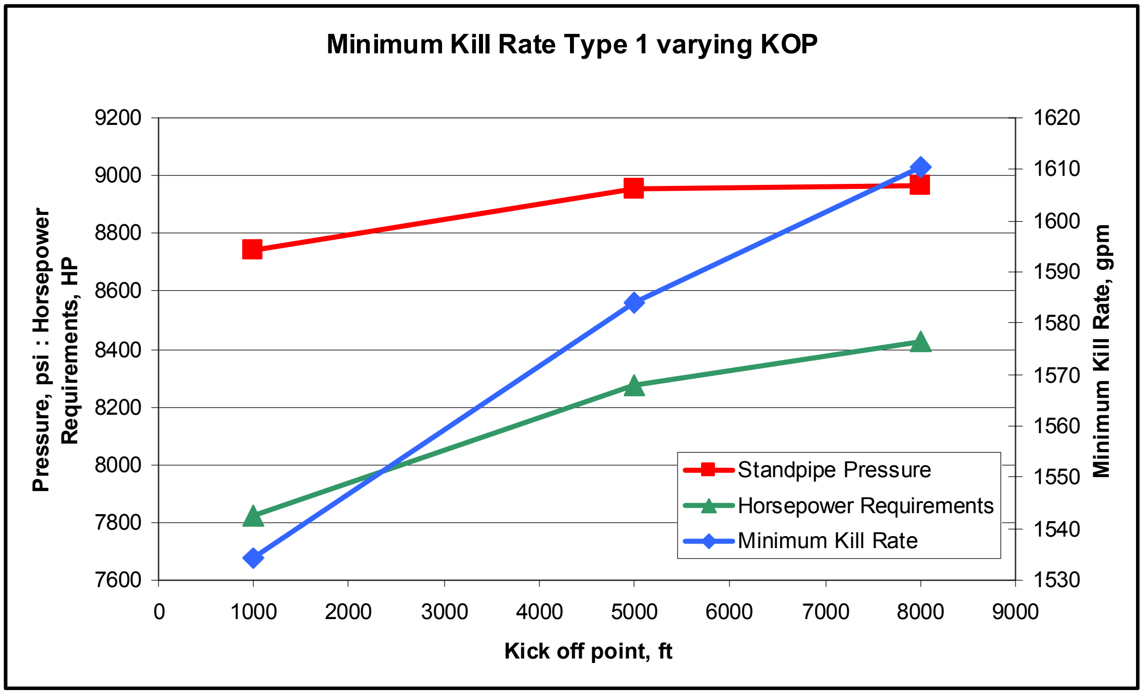

Fig. 4.4 – Increasing KOP increases the minimum kill rate requirement

In the previous simulations BUR and KOP were tested and they will not be tested for the build, hold and drop geometries. The three parameters tested are departure angle, DOR and hold length. The later variation was similar to the second kick off point, the depth where the drop off starts. At times it is difficult to isolate one parameter without affecting another. In the simulations varying hold length the second kickoff point has to be varied to keep the 15000 ft vertical depth. Nine variations of the build hold and drop theme were run.

A common trait with the building radius is there is little difference between 5°/100ft and 10°/100ft. This is apparent in **Fig 4.5**. The first simulation run was the variation of DOR; this is the same as the BUR except that it runs deeper instead of laterally.

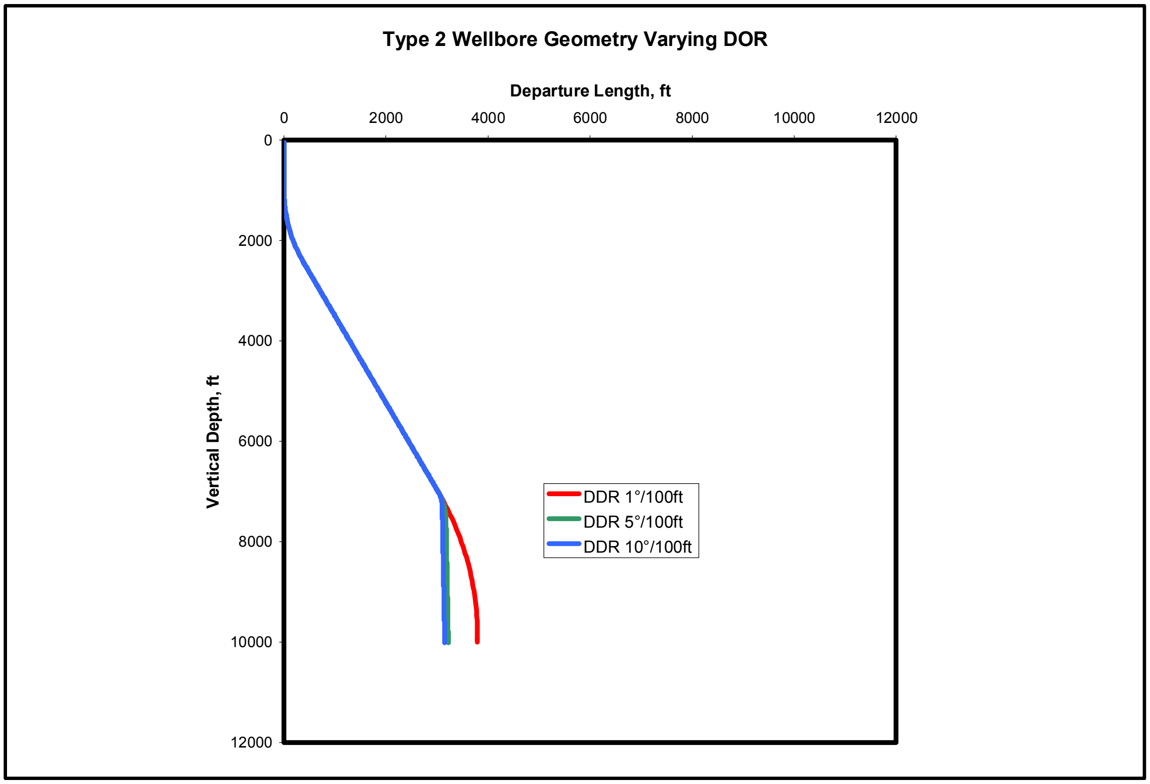

Fig. 4.5 – Type 2 wellbore geometry with varying DOR

Fig.4.6 shows that with increasing DOR the minimum kill rate requirement increases. The difference in minimum required kill rate between a 5 and 10°/100ft rate is only 1 gpm as a result of the measured depths between them are 12 ft. The kill rate for a DOR of 10°/100ft is 1571 gpm while a DOR of 1°/100ft is 1562 gpm.

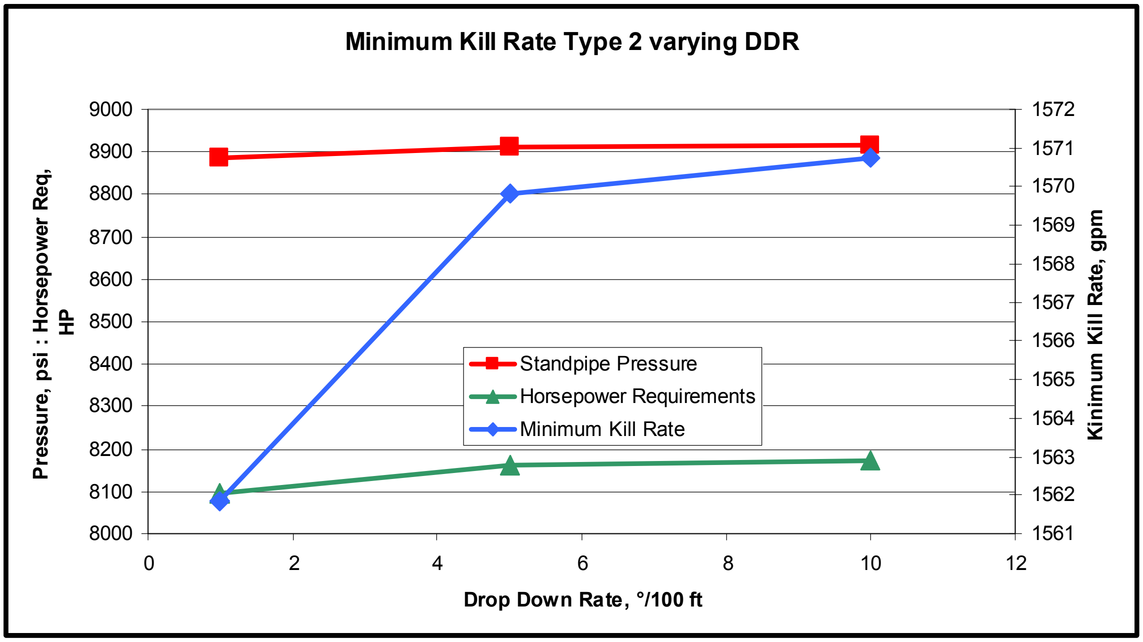

Fig. 4.6 – Minimum kill rate increases with increasing DOR

The second variation includes variable hold length. The second KOP in this simulation varies as a response to the hold length. Three values of hold length included 667 ft, 4122 ft and 6489 ft. **Fig. 4.7** illustrates wellbore geometry with varying hold length. The wellbore with the largest hold length has the greatest horizontal departure. The BUR and the DOR are both 2°/100 ft and the initial KOP occurs at 1000 ft below the mud line. The build and drop angle are both 30° so that the well returns to vertical.

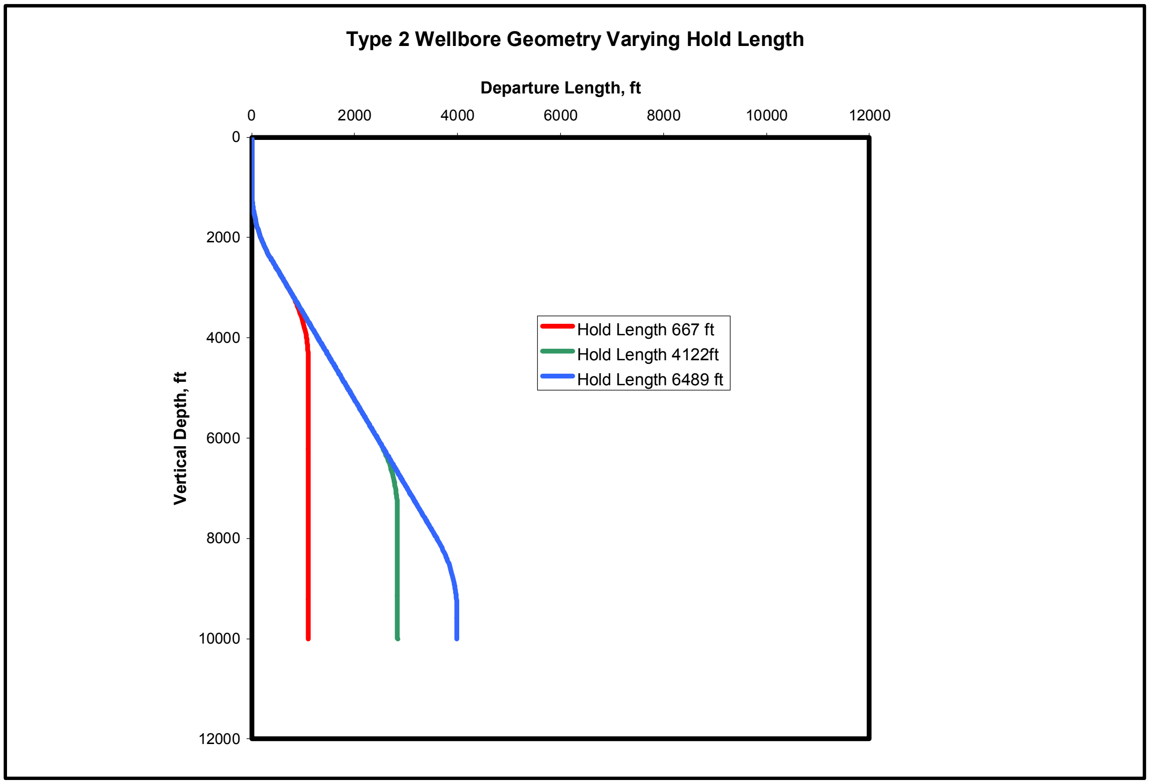

Fig. 4.7 – Wellbore geometry of a Type 2 well varying hold length

Minimum kill rate decreases with increasing frictional pressure from added measured depth. The shortest hold length results in the highest minimum required kill rate of 1619 gpm, **Fig 4.8**. The longest hold length provides the extra frictional pressure and decreases the requirement to 1560 gpm. Stand pipe pressure is dependent on the minimum required kill rate therefore this value also decreases. More horsepower is required to pump kill fluid at a higher rate and less is need for a lower kill rate, therefore with longer measured depth less horsepower is needed to kill the well.

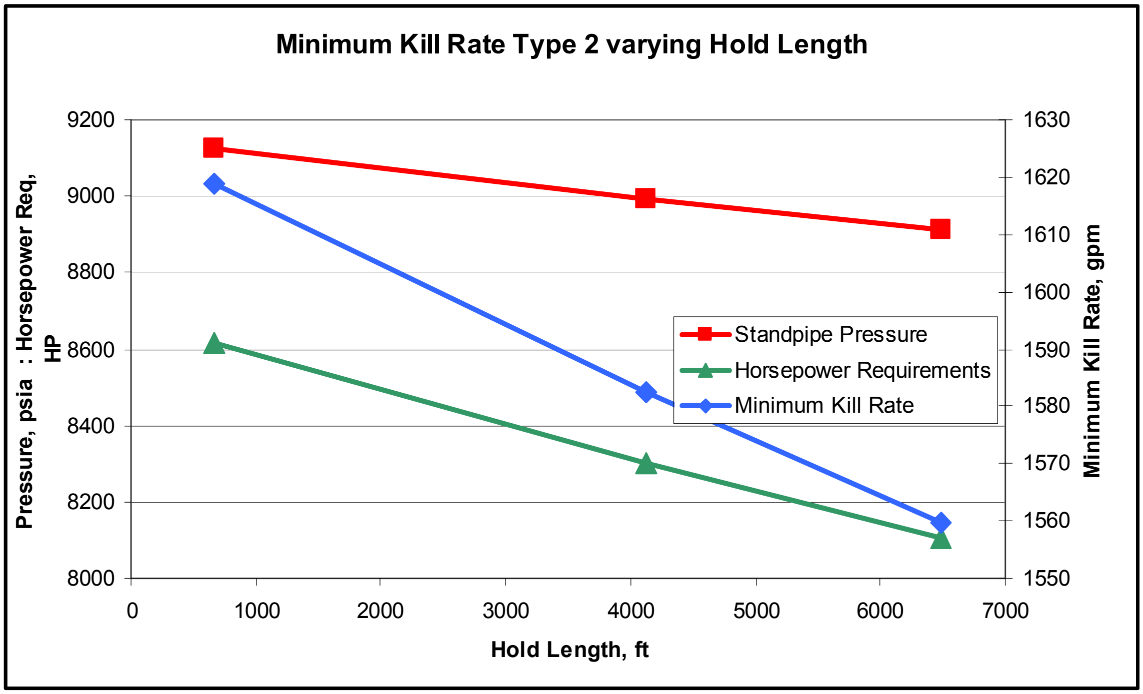

Fig. 4.8 – Increasing hold length decrease minimum kill rate requirement

The last variation run for the Type 2 wellbore geometry was the departure angle. Departure angle is explained in **Fig. 4.9**. This is the angle from the hold section going clockwise. 5°, 15° and 25 ° were tested. **Fig 4.10** shows the shape of the three geometries. The first kickoff point is constant at 1000 ft and the BUR and angle are constant at 2°/100 ft and 30 degrees. The length of the hold is also constant at 5280 ft.

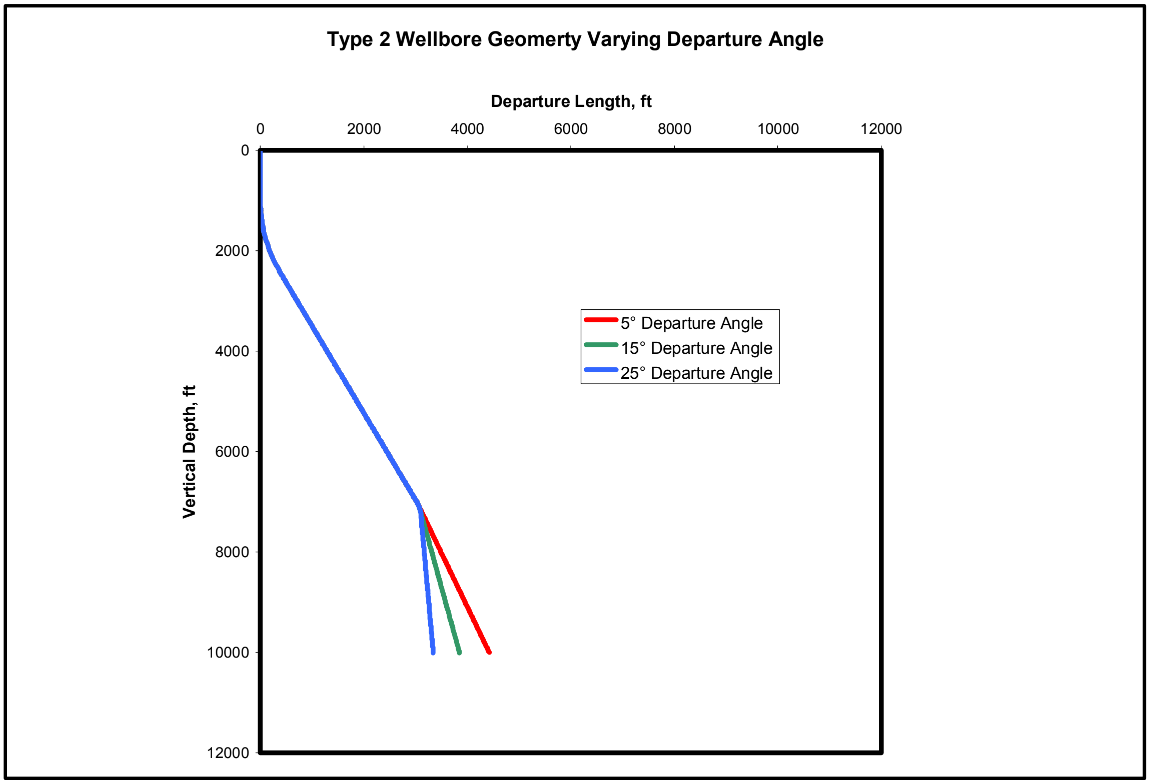

Fig. 4.10 – Type 2 wellbore geometry varying departure angle

As expected the minimum kill rate required is less with a 5° departure angle and greater with a 25° departure, **Fig 4.11**. A 25 gpm kill rate drop can be seen from 1557 gpm to 1535 gpm between the 5° and 25° departure. Standpipe pressure and horsepower has an increasing trend towards the higher departure angle.

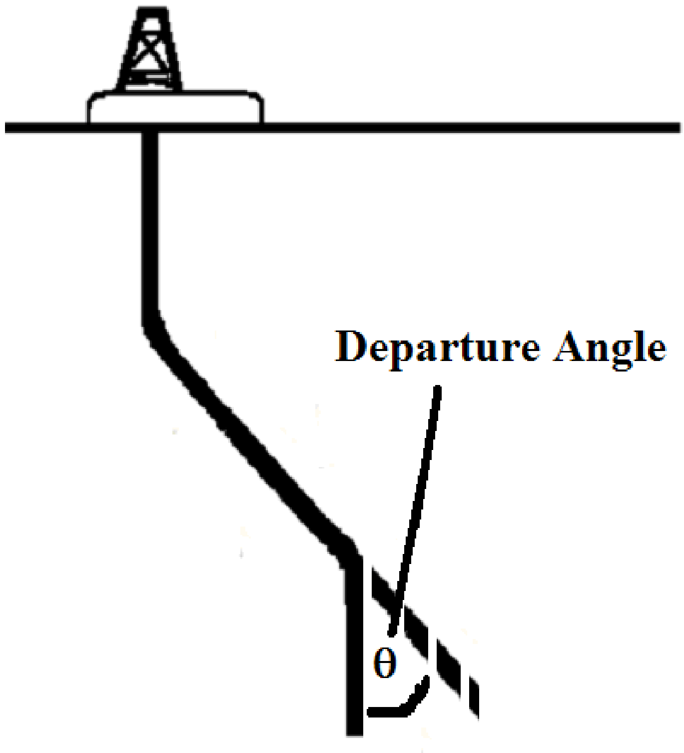

Fig. 4.11a – Departure angle

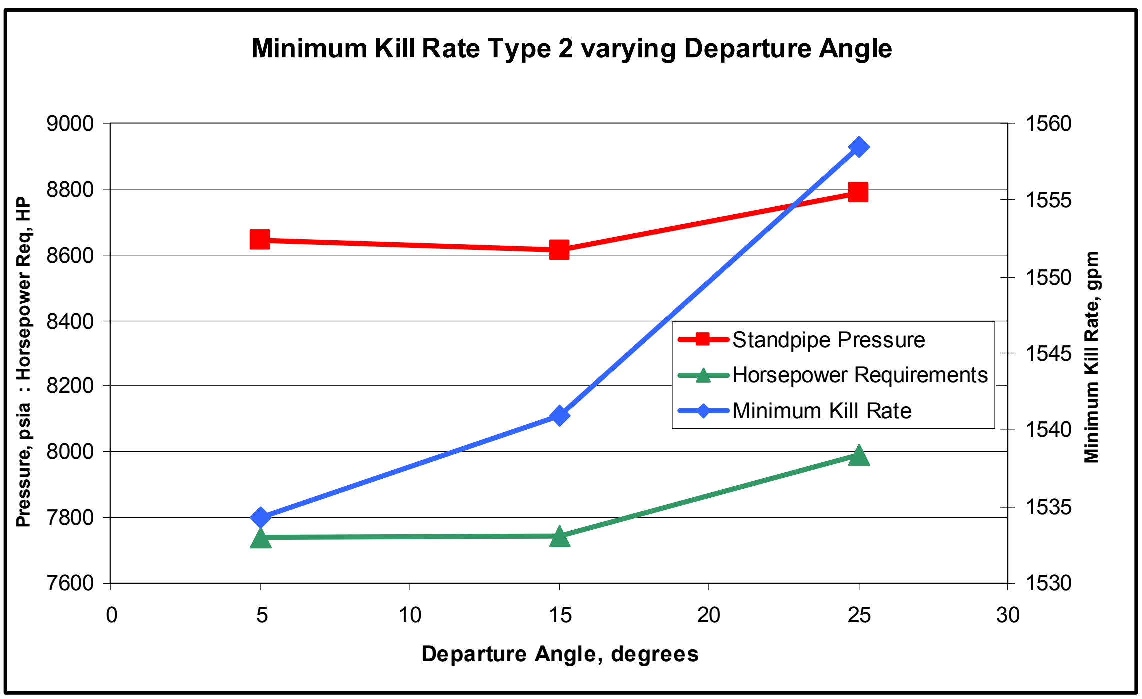

Fig. 4.11b – Increasing departure angle increases the minimum kill rate requirement

Three Type 3 wellbore geometry runs were performed varying the BUR; 0.5°/100ft, 1°/100ft and 5°/100ft. The three wellbore configurations are shown in **Fig. 4.12**. On all three tests the well was built up to 60° but to keep this constant the KOP was varied accordingly.

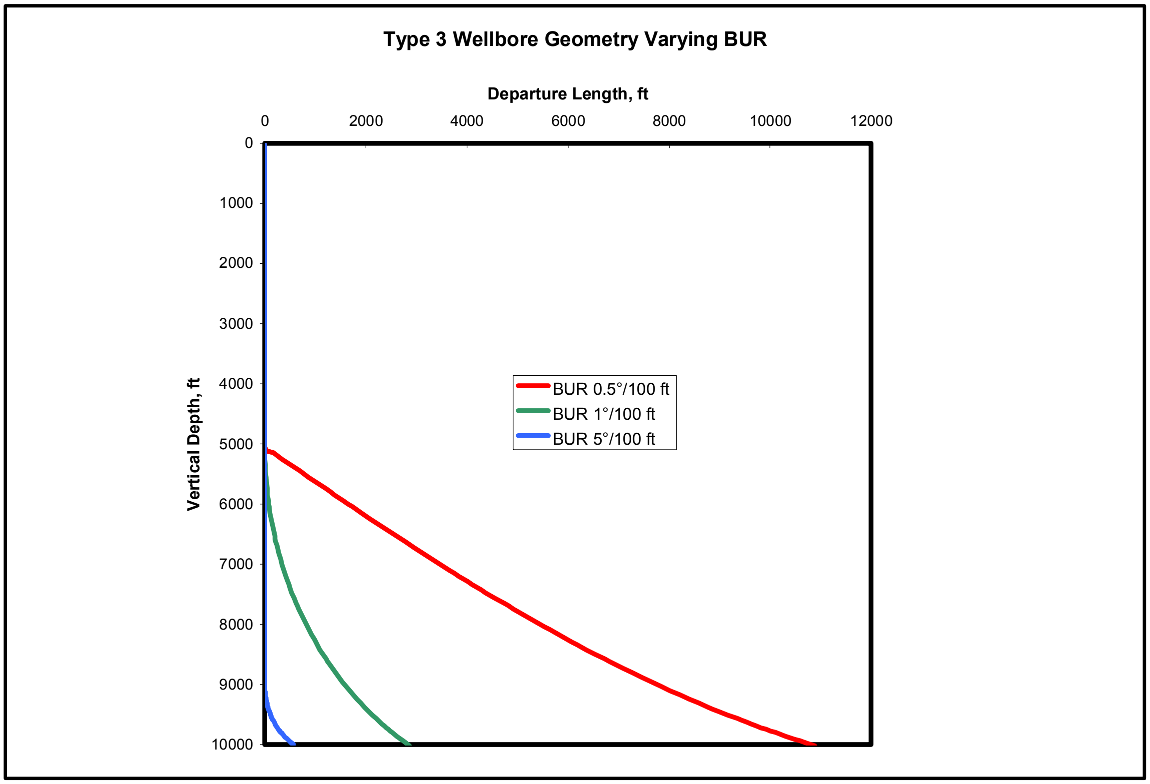

Fig. 4.12 – Type 3 wellbore geometry varying BUR

This simulation clearly defines the relationship of measured depth and kill rate. With a low build-up rate the minimum required kill rate is 1230 gpm as opposed to the nearly vertical BUR of 5°/100 ft with a minimum required kill rate of 1600 gpm, **Fig 4.13.**

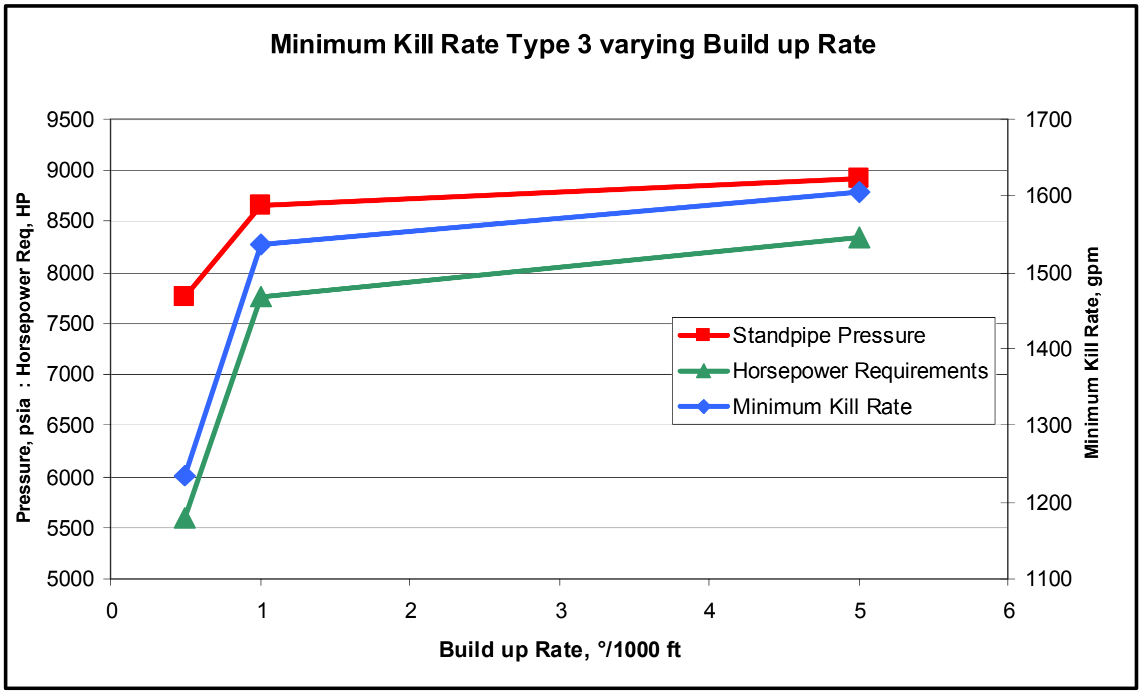

Fig. 4.13 – Minimum kill rate requirements increase with increasing BUR

The last sets of simulations are horizontal well geometries. There are three types of horizontal wells, short, medium, and long radius, the criteria for these were described previously. The geometry of these wells is seen in **Fig 4.14**.

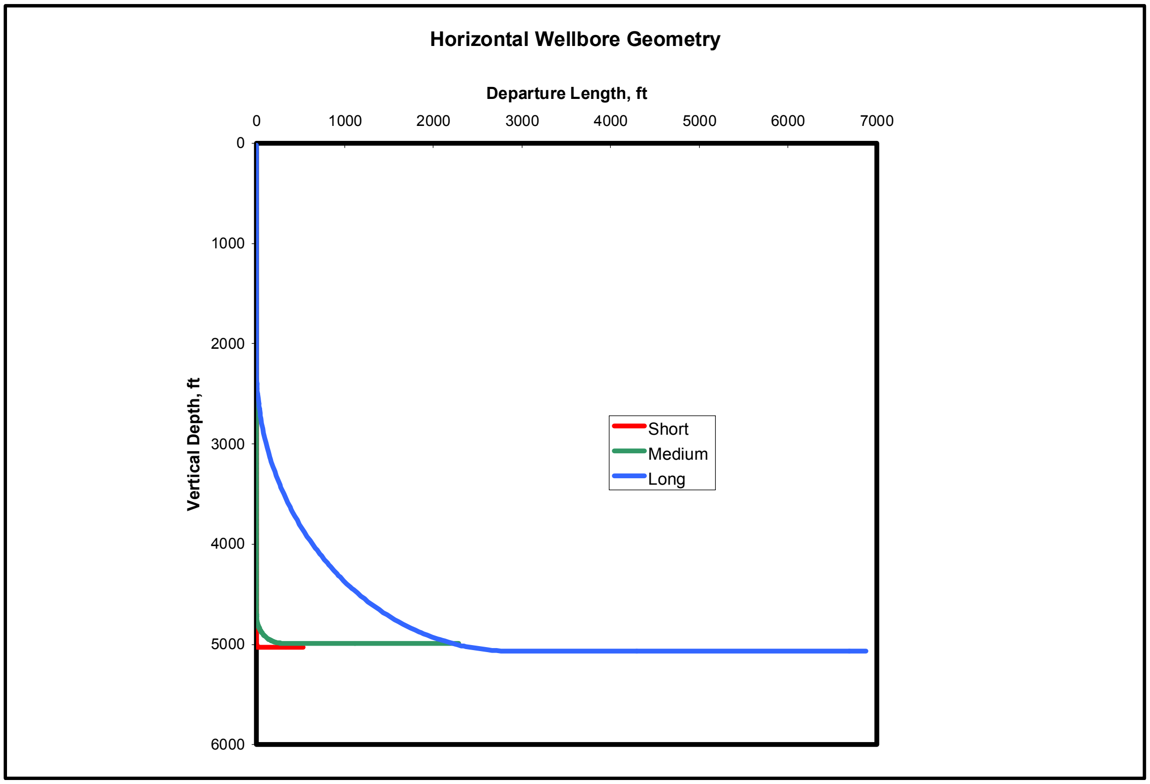

Fig. 4.14 – Wellbore geometry of the three horizontal well simulations

In **Fig 4.15** the horizontal axis corresponds to the type of horizontal well. The short horizontal well corresponds to 1, the medium type is 2 and the long type is 3. As expected the longer horizontal geometry required less minimum kill rate to kill the well. A difference of more than 1000 gpm minimum required kill rate is seen between the long and short horizontal geometries. Standpipe pressure and the horsepower requirements also decrease with the longer horizontal well. Less horsepower is required to pump at a slower rate and at a lower standpipe pressure.

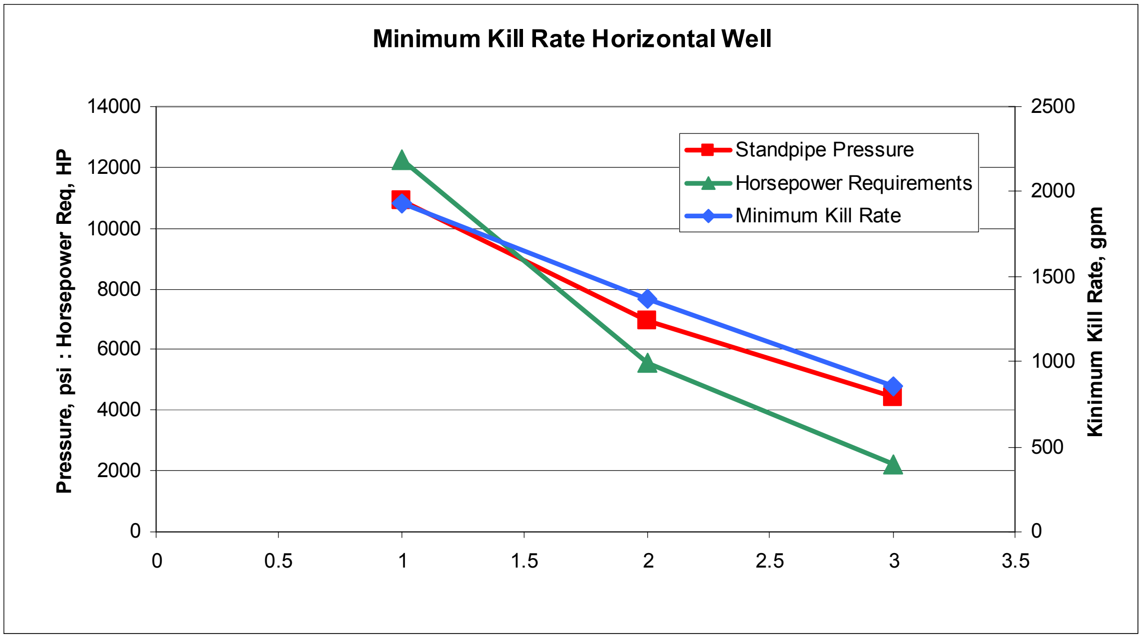

Fig. 4.15 – Minimum kill rate decreases with the size of the horizontal geometry

5. CONCLUSIONS

The original reason to build COMASim was to simulate ultradeep water blowouts and to calculate requirements to kill the well using the dynamic kill method. The selling point of the original program is the simplicity and neatness. New techniques and technologies will be invented and COMASim should keep up with the growth. This new version gave directional capabilities to the original simulator.

COMASim is still in the beginning steps but now it has more functionality now than previously. As with any simulator the quality of the results depends on the quality of input information. COMASim tries to help the user identify inconsistent data, but it is not foolproof; ultimately it is up to the user to make sure that the data provided is accurate and consistent. If the data that is input is unreasonable then the data that is output will be the same. It is very important to input valid data that could be done feasibly in reality.

A common trend observed was minimum kill rate decreasing with increasing measured depth. The added measured depth provides added pressure to the blowing well resulting in lower kill rate of kill fluid to stop the well from flowing. With this information one can conclude that is best to intersect a blowing well at or near the point of influx to benefit from as much frictional pressure as possible.

5.1 Suggestions for Further Work

COMASim 1.0 is a great simple program but it is still somewhat primitive and it should be made a bit more complex to deal with more problems.

5.1.1 Converging Methods

At times COMASim 1.0 has problems converging on a set of data, this does not occur often but it does occur. This is could be due to a number of things, one including the precision of error maybe more than is needed, or the number of iteration steps are not enough to converge, or it could be that a new convergence method is needed. These options would be beneficial to the user to allow them to decide what is best for their situation.

5.1.2 Underground Blowouts

Another area of improvement would be the ability to simulate underground blowouts. At the current moment the user can "fool" COMASim 1.0 by setting the exit pressure to the thief zone to simulate an underground blowout. This is a quick and dirty method to simulate these types of blowouts. The simulator would greatly be improved if it had the ability to have the option to simulate this type of blowout without the confusion.

5.1.3 Multiple Blowing Zones

Rarely does a well blowout of only one zone. When the hydrostatic pressure drops due to an influx of lighter fluid, taking a kick, this may cause other zones to flow into the wellbore. This would improve the accuracy of an actual blowout and make it more robust.

5.1.4 Extras and Miscellaneous

COMASim 1.0 can save results from its simulations, but it does not have the option to open data that has been saved to view at a later time. This does not affect the performance but would make the program far easier to use. Also the addition of a help file would be useful because for simulating dual gradient drilling and underground blowouts sometimes are hard to understand how to do that in the simulator.

NOMENCLATURE

BHP	=	Bottom hole pressure, m/Lt^2
BUR	=	Build up rate, °/L
d	=	Pipe diameter, L
DOR	=	Drop off rate, °/L
f	=	Friction factor
g	=	Gravitational acceleration L/t^2
KOP	=	Kick of point, L
L	=	Length
m	=	Mass
MD	=	Measured depth, L
p	=	Pressure, m/Lt^2
RF	=	Ratio factor
RKB	=	Rotating Kelly Bushing
SMD	=	Survey measured depth, L
SVD	=	Survey vertical depth, L
t	=	Time
UGB	=	Underground Blowout
v	=	Velocity, L/t
VD	=	Vertical depth, L
WMD	=	Wellbore Measured depth, L
Δ	=	Difference
ϕ	=	Angle form vertical
θ	=	Inclination from horizontal
ρ	=	Density, m/L^3

Subscripts

acc	=	Acceleration
c	=	Constant value
calc	=	Calculated value
exit	=	Exit
f	=	Friction
h	=	Hydrostatic
i, k	=	Index numbers
res	=	Reservoir
wf	=	Well flowing

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APPENDIX A

FIGURES

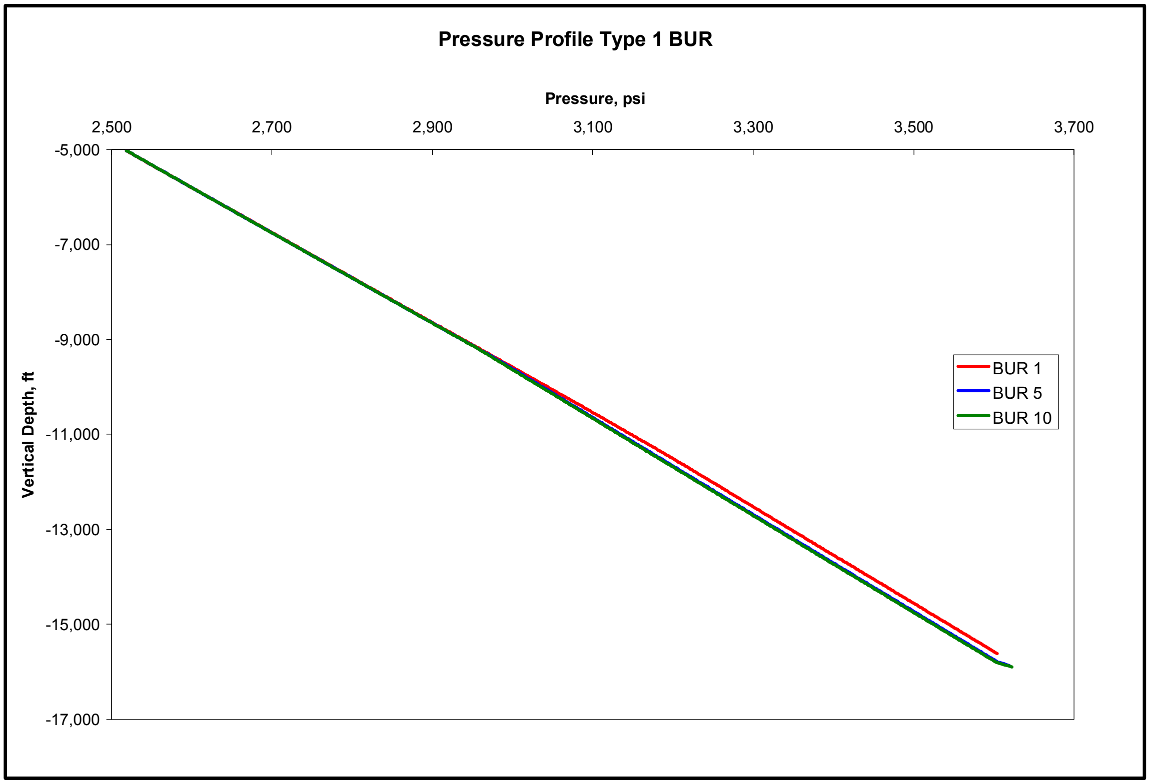

Fig. A.1 – Pressure profile of a Type 1 geometry with varying BUR

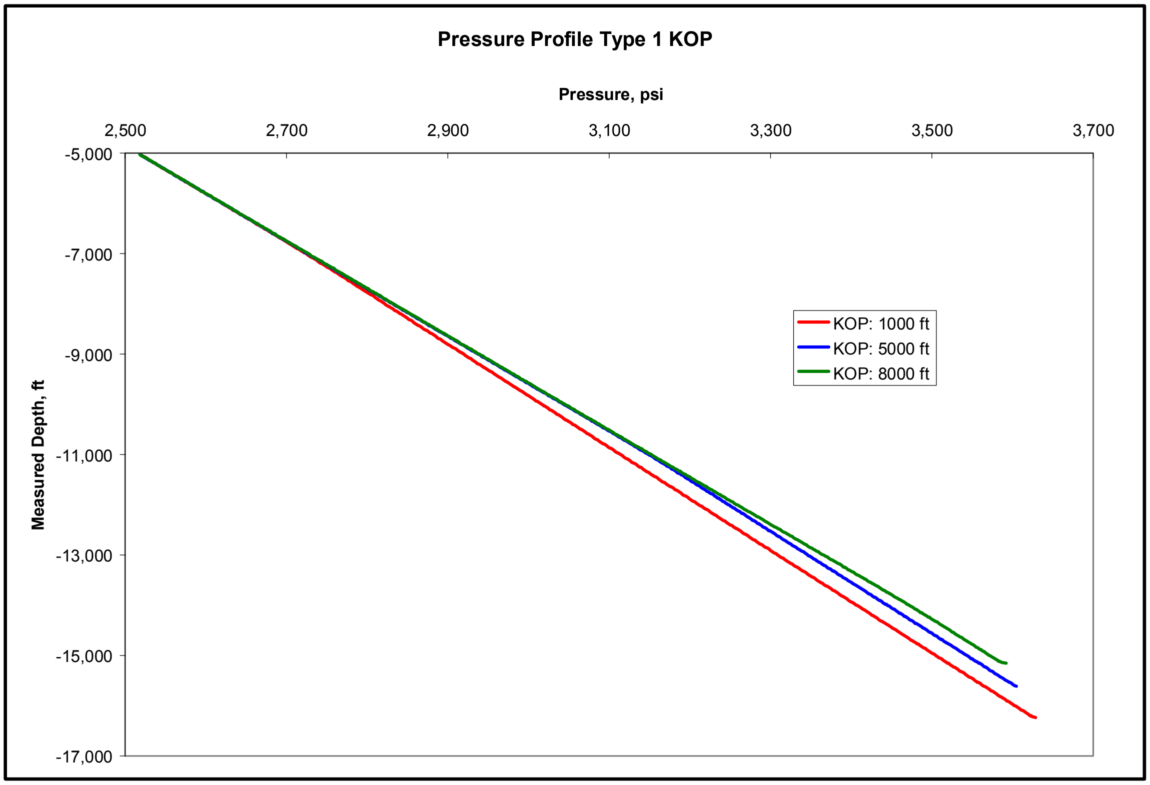

Fig. A.2 – Pressure profile of a Type 1 geometry with varying KOP

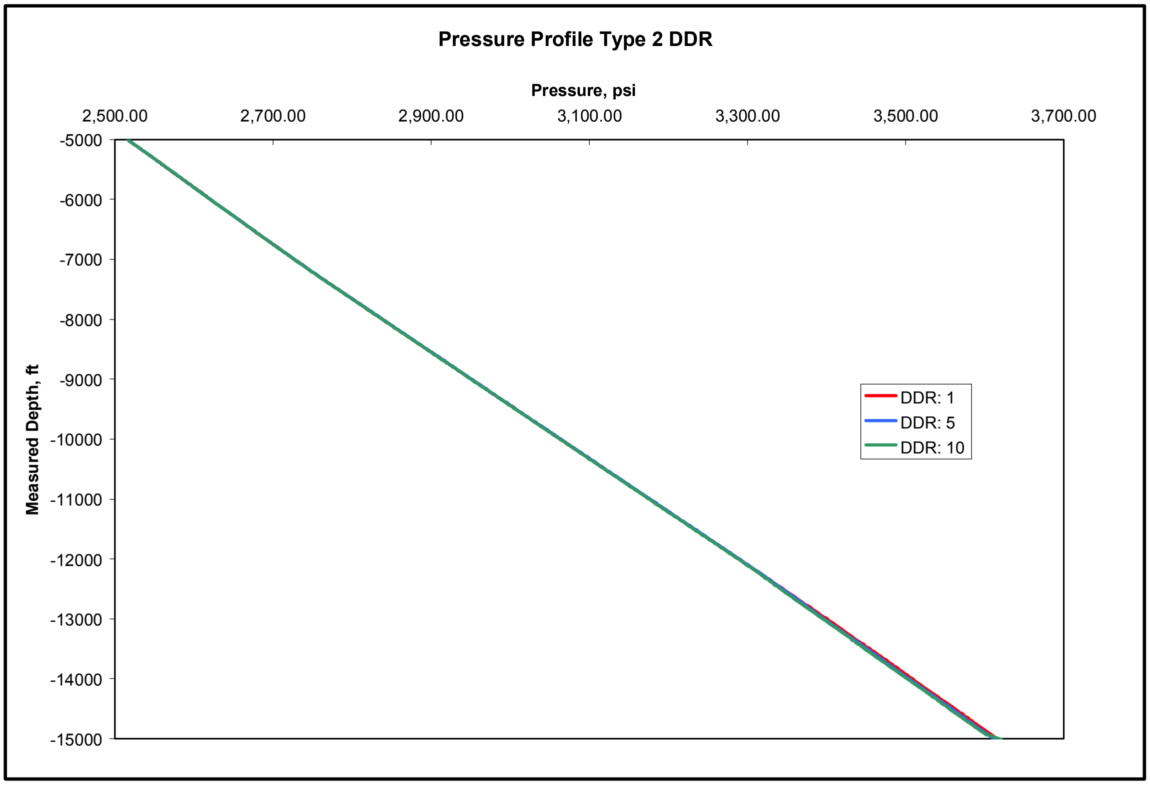

Fig. A.3 – Pressure profile of a Type 2 geometry with varying DOR

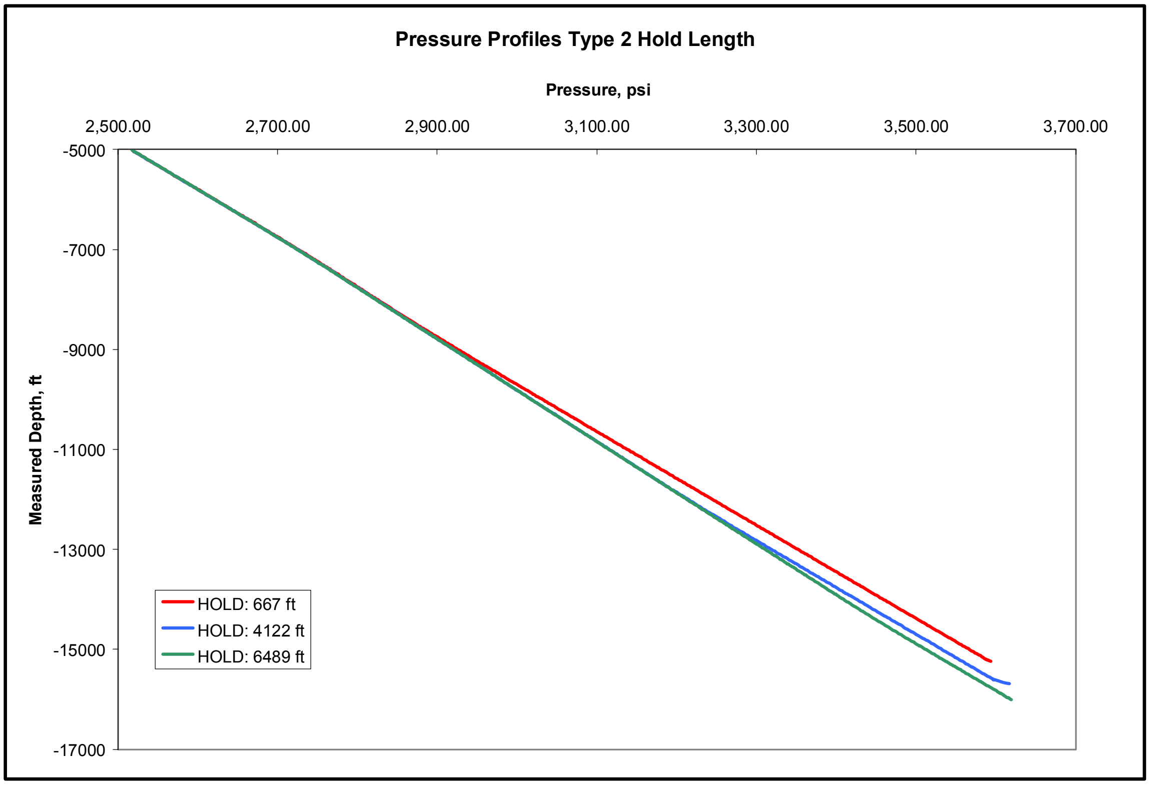

Fig. A.4 – Pressure profile of a Type 2 geometry with varying hold length

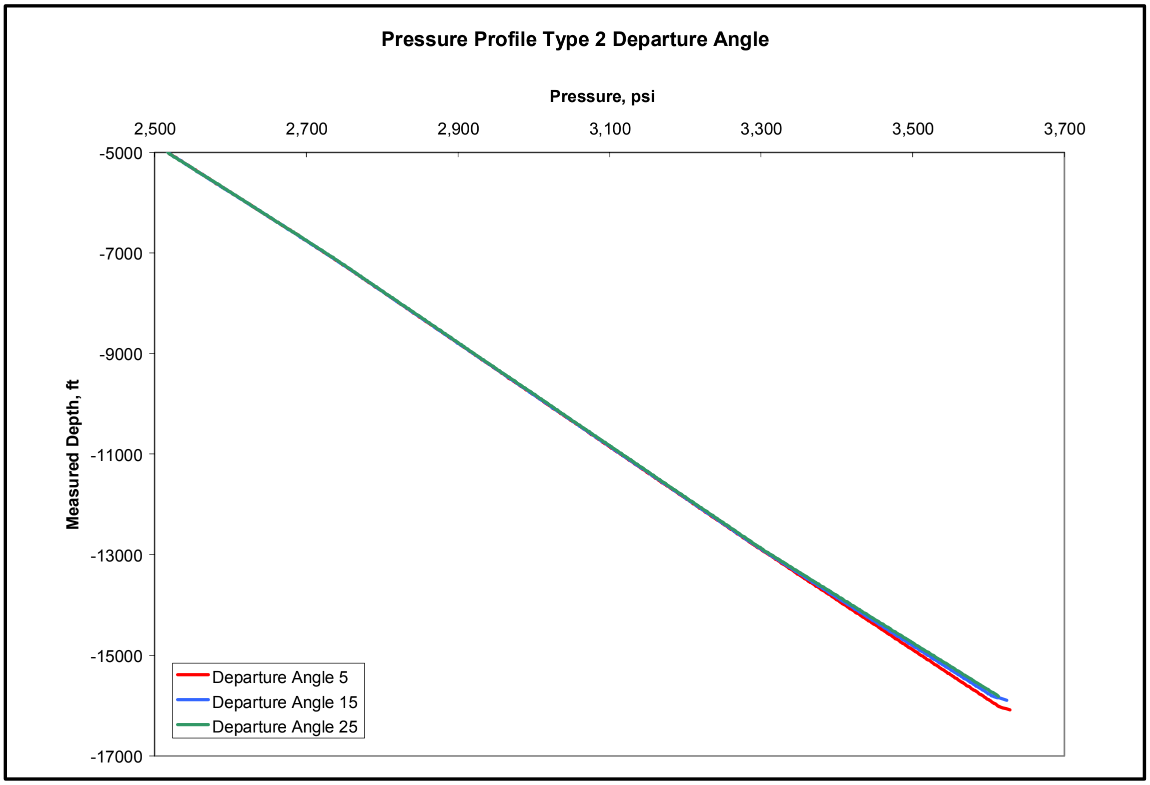

Fig. A.5 – Pressure profile of a Type 2 geometry with varying departure angle

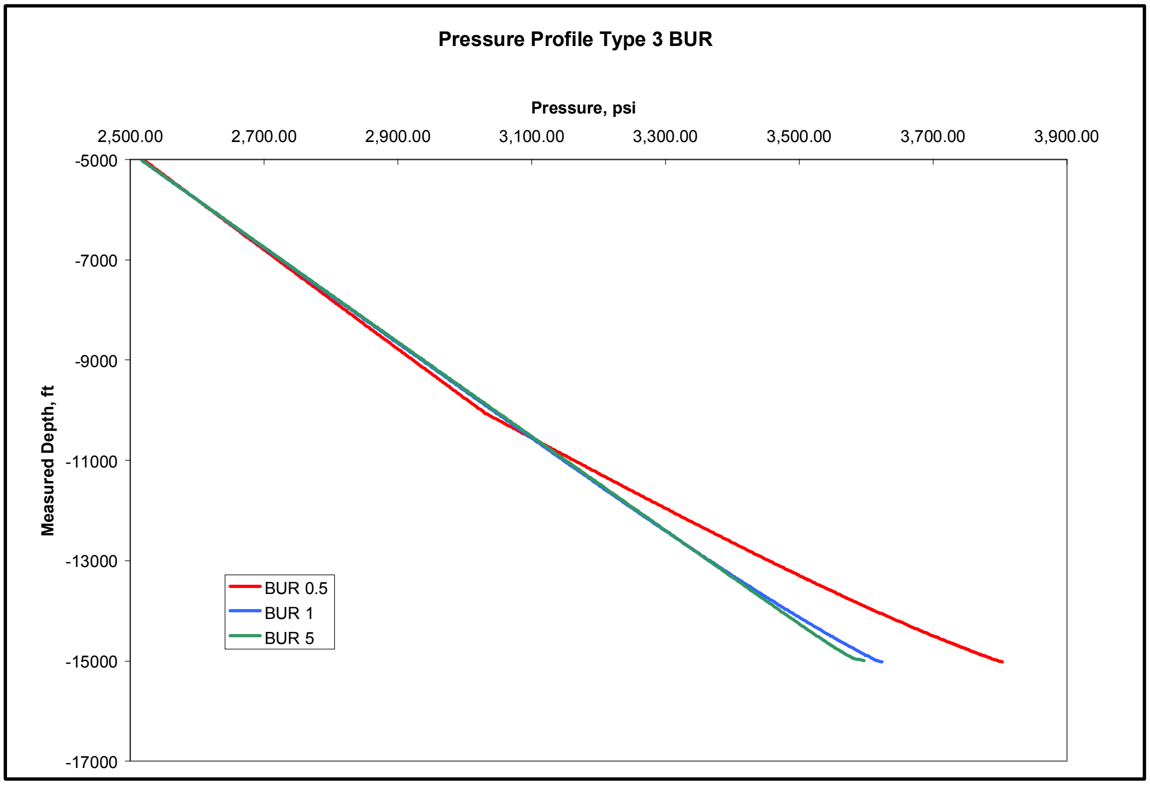

Fig. A.6 – Pressure profile of a Type 3 geometry with varying BUR

APPENDIX B

TABLE

Table B.1 – Example of output results generated by COMASim 1.0

Surface Liquid Rate:	0	STBL/D	Surface Gas Rate:	153.5	MMscf/D		
Minimum Kill Rate:	1534.16	gpm	Pump HP Req:	7823.64	hp	Stand Pipe Pressure:	8740.76

Measured Depth (ft)	Vertical Depth(ft)	Pressure (psia)	Temperature (- F)	Velocity (ft/sec)	Hold-Up
0	0	2,247.38	120	5.24	0
-5,022.28	-5,022.28	2,518.71	120.14	47.66	0
-5,044.75	-5,044.75	2,521.05	120.28	47.64	0
-5,067.23	-5,067.23	2,523.40	120.42	47.61	0
-5,089.71	-5,089.71	2,525.74	120.55	47.59	0
-5,112.19	-5,112.19	2,528.09	120.69	47.57	0
-5,134.66	-5,134.66	2,530.44	120.83	47.54	0
-5,157.14	-5,157.14	2,532.78	120.97	47.52	0
-5,179.62	-5,179.62	2,535.13	121.11	47.49	0
-5,202.09	-5,202.09	2,537.48	121.25	47.47	0
-5,224.57	-5,224.57	2,539.82	121.39	47.45	0
-5,247.05	-5,247.05	2,542.17	121.53	47.42	0
-5,269.52	-5,269.52	2,544.52	121.66	47.4	0
-5,292	-5,292	2,546.86	121.8	47.38	0
-5,314.48	-5,314.48	2,549.21	121.94	47.35	0
-5,336.96	-5,336.96	2,551.56	122.08	47.33	0
-5,359.43	-5,359.43	2,553.91	122.22	47.31	0
-5,381.91	-5,381.91	2,556.25	122.36	47.28	0
-5,404.39	-5,404.39	2,558.60	122.5	47.26	0
-5,426.86	-5,426.86	2,560.95	122.63	47.24	0
-5,449.34	-5,449.34	2,563.30	122.77	47.21	0
-5,471.82	-5,471.82	2,565.65	122.91	47.19	0
-5,494.29	-5,494.29	2,567.99	123.05	47.17	0
-5,516.77	-5,516.77	2,570.34	123.19	47.14	0
-5,539.25	-5,539.25	2,572.69	123.33	47.12	0
-5,561.72	-5,561.72	2,575.04	123.47	47.1	0
-5,584.20	-5,584.20	2,577.39	123.61	47.08	0
-5,606.68	-5,606.68	2,579.74	123.74	47.05	0
-5,629.16	-5,629.16	2,582.08	123.88	47.03	0
-5,651.63	-5,651.63	2,584.43	124.02	47.01	0
-5,674.11	-5,674.11	2,586.78	124.16	46.98	0
-5,696.59	-5,696.59	2,589.13	124.3	46.96	0
-5,719.06	-5,719.06	2,591.48	124.44	46.94	0
-5,741.54	-5,741.54	2,593.83	124.58	46.92	0
-5,764.02	-5,764.02	2,596.18	124.71	46.89	0
-5,786.50	-5,786.50	2,598.53	124.85	46.87	0
-5,808.97	-5,808.97	2,600.88	124.99	46.85	0

APPENDIX C
COMASIM

C.1 COMASim

COMASim is a dynamic kill simulator for ultradeep water. The objectives of a dynamic kill simulator are to determine the initial conditions downhole of a blowing well such as pressures and flowrates, determine the requirements for a dynamic kill (i.e. pump rate, power requirement, and mud volumes) and to better assess the circumstances of the blowing well to make informed decisions to then next course of action.

C.2 Algorithm

The two main objectives of COMASim are to determine the initial blowing condition of the wild well and to determine the minimum kill rate required to stop the influx of formation fluid into the wellbore.

C.2.1 Initial Blowing Conditions

The initial conditions calculated are taken at the time when the well is blowing out. The wellbore model is separated into 500 small elements. The boundary conditions are constant; they are reservoir pressure and exit pressure. Exit pressure is atmospheric pressure if the user selects to have the formation fluids exit the surface or exit pressure is hydrostatic pressure if a sea floor exit is desired. The first step in calculating the initial conditions is the estimation of the wellbore flowing pressure. The initial guess is reservoir pressure. With this estimation and other parameters provided by the user via the inputs (e.g. water cut and gas/liquid ratio), fluid properties for the element are calculated. These fluid properties are used to calculate the pressure gradient between two elements using the multiphase flow correlations. This process is continued from the bottom of the well going upwards until a pressure profile for the wellbore is made. The exit pressure of this wellbore is compared to the exit pressure specified by the user. If the difference between these two values is within an acceptable tolerance, then the estimate for the wellbore flowing pressure is correct. If not, then another estimate for wellbore flowing pressure is calculated. This value is again used to create a new pressure profile of the wellbore and the exit pressure is compared again. This process is continued until the calculated estimated exit pressure is reasonably close to the actual exit pressure or over 100 iterations have been performed. The wellbore flowing pressure is used to calculate the surface flow rate of formation fluids from the inflow performance relationship. The inflow relationship is

$$p_{wf} = \bar{p}_R - \Delta p_{res} \qquad \text{C.1}$$

and the outflow of relationship is

$$p_{wf} = p_{exit} + \Delta p_f + \Delta p_h + \Delta p_{acc} \qquad \text{C.2}$$

These two equations are graphed as functions of flow rate as seen in **Fig C.1**. The point of intersection of these functions results in the surface flow rate.

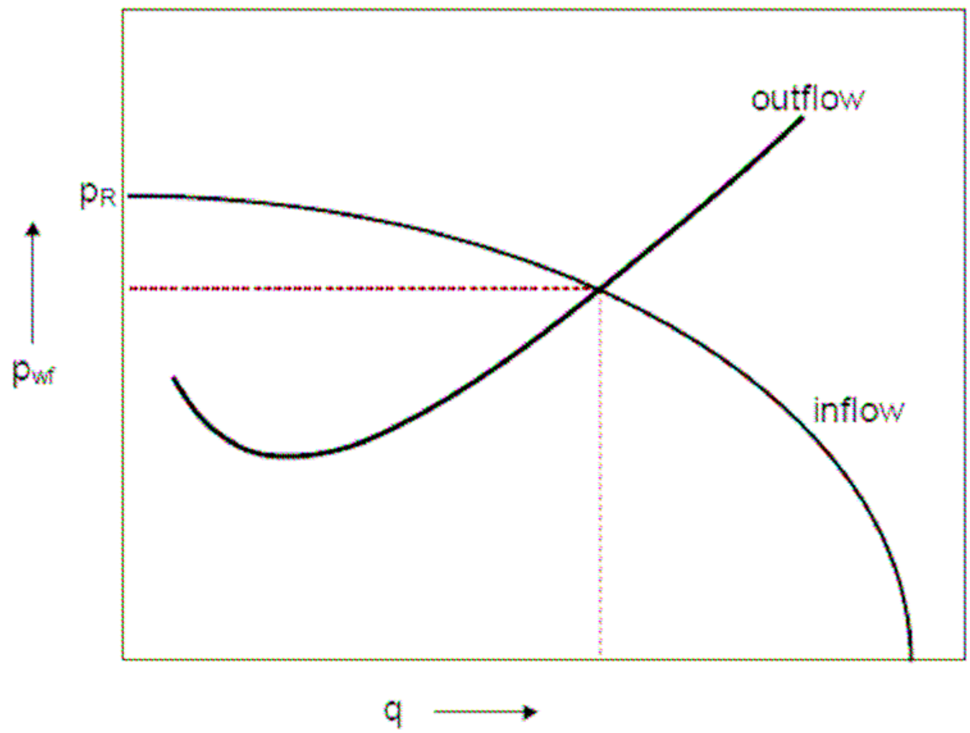

Fig. C.1 – Bottomhole pressure and initial flowrate is obtained using the nodal analysis approach

C.2.1 Minimum Kill Rate

The minimum kill rate is a very important figure to know to effectively kill a blowing well using the dynamic kill method. The first step in this process is to calculate the minimum kill rate for a single phase solution. This requires an estimate of minimum kill rate. With the exit pressure known, bottomhole flowing pressure is calculated similar to the way it was computed in the initial conditions. When the difference between reservoir pressure, supplied by the user, and bottomhole flowing pressure is within an acceptable tolerance, then the iterations stop, if not, it continues until a solution is found. This single phase solution kill rate is then used as the minimum kill rate estimate for the multiphase solution algorithm to calculate minimum kill rate. In the multiphase flow algorithm a wellbore pressure profile is made and the bottomhole pressure is compared with reservoir pressure. If the bottomhole pressure is greater than reservoir pressure, the assumption is that no liquid loading occurs and the single phase solution is valid.

If the bottom hole calculated is less than the reservoir pressure, the system intake curve and the inflow performance curve have to be compared. If the intake curve lies below the inflow performance curve then the kill rate has to be increased and new single-phase system-intake curve must be calculated. If the system-intake curve is above the inflow-performance curve a new single-phase system intake curve is calculated using a larger influx. This process is continued until the bottomhole pressure increases and a the minimuk kill rate is found, **Fig. C.2**.

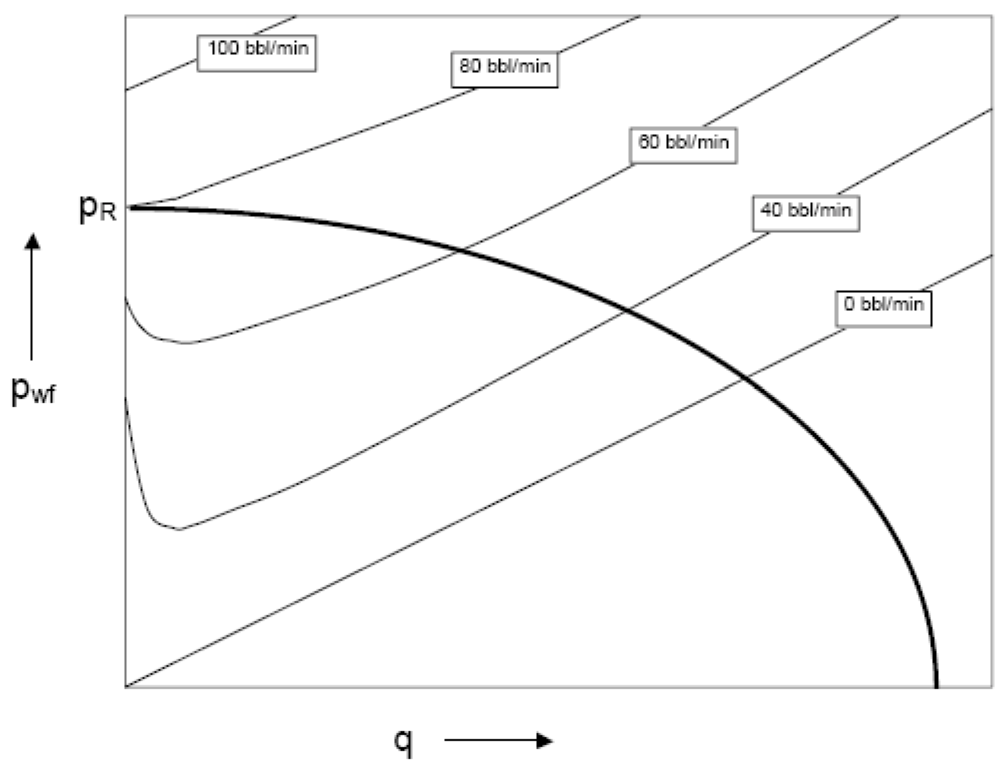

Fig. C.2 – System intake curves for various kill rates

APPENDIX D
COMSIM USER MANUAL

D.1 Introduction

This user manual is not intended to solve every single scenario but is only used as a general guideline on the basic usage of COMASim. As was discussed in previously COMASim has several sections. Once COMASim has started it opens to a screen as shown in **Fig. D.1**.

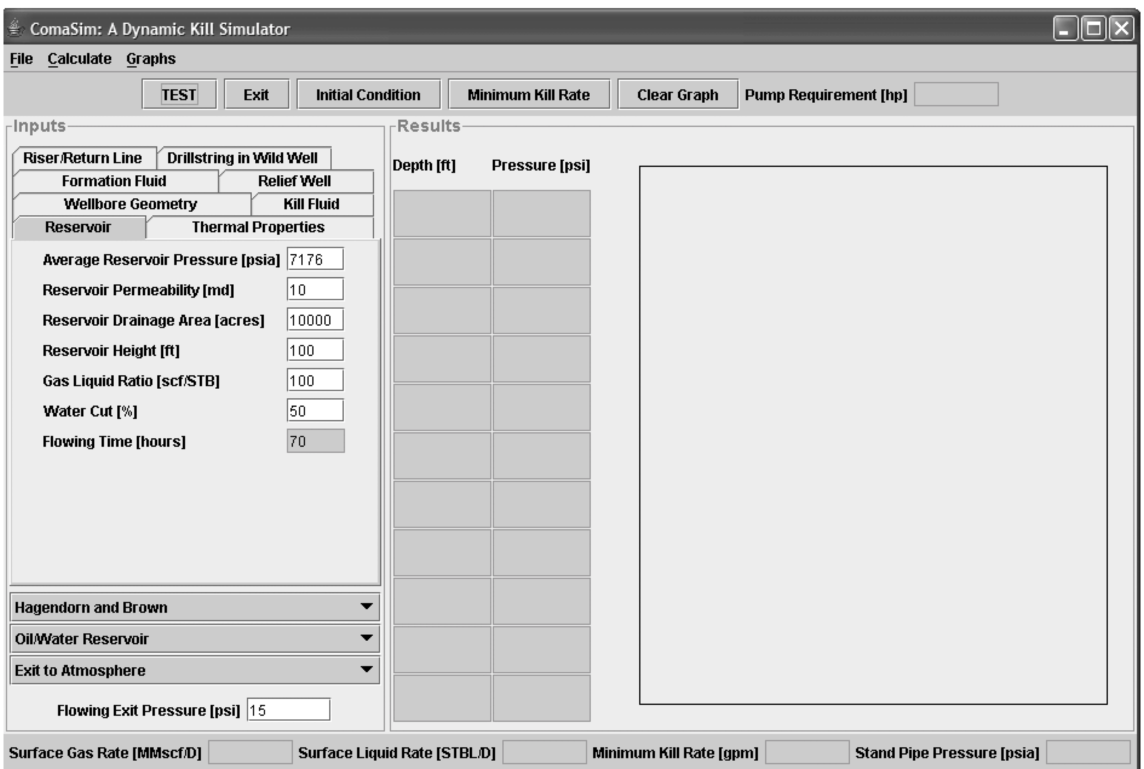

Fig. D.1 – Opening screen

D.2 Inputs

The information that will be supplied by the user will be entered in the input section, the left side of the opening screen.
There are 8 tabs in the input section, reservoir, thermal properties, wellbore geometry, kill fluid, formation fluid, relief well, riser return line and drillstiring in wild well.

D.2.1 Reservoir

In the reservoir tab the user inputs data that is pertinent to the reservoir properties of the blowing well. These properties include, average reservoir pressure, reservoir permeability, reservoir drainage area, reservoir height, gas/liquid ratio, water cut and flowing time. The flowing time is not an input but rather it is calculated from the users inputs. The units are in oil field units and every text field box should be filled.

D.2.2 Thermal Properties

The first choice in the thermal properties tab is the selection of the temperature model; straight line, Ramey and Shui and Beggs. This should be chosen first. Then depending on what type of model is chosen, some text fields may be grayed out, meaning that the parameter is not need in the calculations. The inputs include geothermal gradient, exit temperature, specific heat at constant volume, specific heat at constant pressure, Earth thermal diffusivity, heat transfer coefficient, formation thermal conductivity and the Joule-Thompson Coefficient.

D.2.3 Wellbore Geometry

A major choice in this tab is whether the well is a vertical well or a directional well. If vertical is selected then all of the text field blocks should be filled. If the directional radio button is selected, a file dialogue box will appear and will allow the user to select the depth file. The total vertical depth does not need to be input when the directional well is selected. Other parameters include water depth, casing depth from sea level, open hole diameter, casing inner diameter, absolute pipe roughness and open hole roughness.

D.2.4 Kill Fluid

In this tab the properties of the kill fluid is input. These parameters include mud weight, yield point, plastic viscosity, mud salinity and surface temperature.

D.2.5 Formation Fluid

The formation fluid properties are in this tab and all of the text boxes should be filled. The input parameters are gas specific gravity, molar H2S, CO2 and N2 content, oil API gravity, oil bubble point pressure, water specific gravity, water salinity and specific heat of liquid. Depending on what multiphase flow model chosen depends on which text fields will be grayed out.

D.2.6 Relief Well

Two choices are given for the type of flow through the relief well, annular flow or pipe flow. Click on the desired radio button to make your selection. The parameters needed are measured depth, vertical depth, pipe roughness, annular inner diameter, pipe outer diameter, pipe inner diameter, and number of relief wells. Sometime one relief well may not be enough to kill a well; therefore the option to select extra wells is available. The measured depth and vertical depths of the relief well refer to the total depths from the surface.

D.2.7 Riser/Return Line

Riser outer diameter, riser inner diameter, buoyancy material outer diameter, buoyancy material depth from mean sea level, riser heat transfer coefficient, buoyancy heat transfer coefficient and riser roughness are inputs for the riser/return line tab. When the user selects the exit to seafloor condition then all but the last parameter are grayed out.

D.2.8 Drillstring in Well

Here the user selects one out of four scenarios for the drill pipe; hanging, dropped to bottom, kill with drill string or no drill string. Depending on which scenario is selected, some or all of the text fields may be grayed out. The input parameters for this tab include drillstring outer diameter, drillstring inner diameter, drillstring length, drillcollar outer diameter, drillcollar inner diameter, drillcollar length, and drill string roughness.

D.3 Multiphase Flow/Reservoirs/Exits

Right below the input tabs there are three pulldown menus, one for the multiphase flow model, one for the type of reservoir and one for the choice of exit of the formation fluids. To select an option the user clicks on the button and selects their choice. As mentioned in this thesis three multiphase models are available; Duns and Ros, Hagedorn and Brown and Beggs and Brill.

Two types of reservoirs are available under this menu: oil/water reservoir and gas reservoir. Finally the user has the option to chose where the formation fluids exit; to the surface or to the mudline.

Right below these menus there is a text field for flowing exit pressure. This is usually automatically calculated; in the case of an underground blowout the exit flowing pressure is the pressure of the formation taking the formation fluid.

D.4 Results

After the information is input the user clicks the button marked initial conditions from the top. This generates a pressure profile of the blowing well and calculates the surface gas rate and surface liquid rate of the blowing well. These values are found on the bottom right of the COMASim window. Then the user may click the minimum kill rate button. This will calculate the minimum kill rate, stand pipe pressure and the pump requirements. These values are found on the bottom right and top right of the COMASim window.

D.5 Graphs

After the Minimum kill rate button has been clicked then the user may look at other types of graphs. These graphs include: *Vertical Depth vs. Pressure, Vertical Depth vs. Temperature, Vertical Depth vs. Velocity, Vertical Depth vs. Liquid Hold Up, Measured Depth vs. Pressure, Measured Depth vs. Temperature, Measured Depth vs. Velocity, Measured Depth vs. Liquid Hold Up* and *Wellbore Trajectory.* These charts can be found from the menu bar under the graphs menu.

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